Technical Support Document

for the

Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan

(Cost TSD)

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Technical Support Document for the Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan

1 Introduction

This TSD describes how we conducted cost analyses for retrofitting certain coal fired EGUs with Spray Dryer Absorbers (SDA, or dry scrubbers), Wet Flue Gas Desulfurization (wet FGD), Dry Sorbent Injection (DSI); and how we conducted cost analyses on upgrading certain existing wet FGD scrubbers. This work is a part of our review of the Texas and Oklahoma regional haze State Implementation Plans (SIPs).

In the process of developing our cost analyses, we consulted with Dr. Phyllis Fox, Ph.D., P.E., a consultant to RTI International under contract EP-W-11-029, Work Assignment No. 3-09. Dr. Fox contributed significantly to Section 6, concerning upgrading existing scrubbers. Dr. Fox also reviewed and provided comments on Sections 3, 4, and 5, concerning the cost analyses for SDA and wet FGD scrubber retrofits, and the cost analyses for DSI. Dr. Fox did not have access to any claimed Confidential Business Information for this work.

We are conducting a SO_2 cost analyses for the following facilities and units:

Table 1. Sources undergoing RP and LTS analyses

Facility	**Units**	**Scrubbed?**	**Bypass?**
Big Brown	1, 2		
Sandow 4	1	Y	Y
Monticello	1, 2		
Monticello	3	Y	Y
Martin Lake	1, 2, 3	Y	Y
Coleto Creek	1		
Limestone	1, 2	Y	Y
San Miguel	1	Y	N
Tolk	1, 2		
Welsh	1, 2, 3		
W. A. Parish	5, 6, 7		
W. A. Parish	8	Y	Y

For those units without a scrubber, we calculate the costs for DSI, dry scrubbing, and wet scrubbing. For those units that are equipped with an underperforming scrubbing system, we calculate the costs of upgrading that scrubbing system. We also document the level of SO_2 removal efficiencies we believe is appropriate, depending on the technology.

We have constructed a master spreadsheet[1] that contains information concerning ownership, location, boiler type, environmental controls and other information that we draw upon throughout this appendix. This spreadsheet includes information contained within Texas' computer-based State of Texas Air Retrieval System (STARS) database,[2] our CAMD emissions data,[3] EIA Form 860,[4] and our National Electric Energy Data System (NEEDS) database associated with our Integrated Planning Model (IPM).[5] We rely upon this information for our analysis, confirmed when possible through other public sources of information such as permitting files and trade journals.

2 Cost Analyses Methodology

In developing our cost estimates for the units in Table 1, we relied on the methods and principles contained within the EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual).[6] As we describe in our Oklahoma final action,[7] the Control Cost Manual uses the "overnight" method of cost estimation:

> The Control Cost Manual uses the overnight method of cost estimation, widely used in the utility industry. The U.S. Energy Information Administration (EIA) defines ''overnight cost'' as ''an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day. This concept is useful to avoid any impact of financing issues and assumptions on estimated costs.'' EIA presents all of its projected plant costs in terms of overnight costs. The overnight cost is the present value cost that would have to be paid as a lump sum up front to completely pay for a construction project. The overnight method is appropriate for BART determinations because it allows different pollution control equipment to be compared in a meaningful manner. Because ''different controls have different expected useful lives and will result in different cash flows, the first step in comparing alternatives is to normalize their returns using the principle of the time value of money ... The process through which future cash flows are translated into current dollars is called present value analysis. When the cash flows involve income and expenses, it is also commonly referred to as net present value analysis. In either case, the calculation is the same: Adjust the value of future money to values based on the same point in time (generally year zero of the project), employing an appropriate interest (discount) rate and then add them together.''

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1 This spreadsheet, entitled "TX Sources of Interest-new.xls," is located in our docket.
2 http://www.tceq.texas.gov/airquality/point-source-ei/psei.html
3 http://ampd.epa.gov/ampd/
4 http://www.eia.gov/electricity/data/eia860/
5 http://www.epa.gov/airmarkt/progsregs/epa-ipm/BaseCasev410.html#needs
6 EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002 available at http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf.
7 77 FR 81744.

We proceed in our SO_2 costing analyses by examining the current SO_2 emissions and the level of SO_2 control, if any, for each of the units listed in Table 1. For the units in Table 1 without any SO_2 control, with the exception of the PPG flat glass plant, we calculated the cost of installing DSI, a SDA scrubber, and a wet flue-gas desulfurization (FGD) scrubber.

In order to estimate the costs for DSI, SDA scrubbers, and wet FGD scrubbers, we programmed the DSI, SDA and wet FGD cost algorithms, as employed in version 5.13 of our IPM model, [8] into three spreadsheets. These cost algorithms calculate the Total Project Cost (TPC), Fixed Operating and Maintenance (Fixed O&M) costs, and Variable Operating and Maintenance (Variable O&M) costs. We verified these spreadsheets by reproducing the costs estimated by Sargent & Lundy in the project reports. We further extended these cost algorithms to calculate the annualized costs per ton of SO_2 removed ($/ton). We then performed DSI, SDA and wet FGD cost calculations for each unit listed in Table 1 that did not already have SO_2 control. These spreadsheets are entitled, "DSI Cost IPM 5-13 TX Sources.xlsx," "SDA Cost IPM 5-13 TX Sources.xlsx," and "Wet FGD Cost IPM 5-13 TX Sources.xlsx," and are located in our Docket. We discuss the inputs and outputs for the DSI, SDA, and wet FGS cost models below. These cost models were based on costs escalated to 2012 dollars.[9] Were we to escalate these costs to 2013 dollars, the capital costs would decrease by approximately 3%, because the CEPCI index for 2013 (567.3) is less than the index for 2012 (584.6). We have conservatively elected to leave the capital costs at their 2012 values. We present the results of our DSI, SDA, and wet FGD cost analyses in sections 3, 4, and 5.

3 Overview of DSI Cost Model Input Parameters

Table 2, below, is a depiction of the input section of the DSI cost spreadsheet. Sample input parameters for the DSI cost calculation are represented by yellow highlighted cells. The input values designated "A" through "U" have the same meaning as those contained within the documentation for the IPM DSI cost algorithms (hereafter referred to as the "IPM DSI documentation") referenced above. The last four input values, (i. e., Interest rate, Equipment Lifetime, Gross Load, and Baseline) were added by us in order to calculate the annualized costs per ton of SO_2 removed ($/ton). Those cells that are not highlighted in yellow are interim calculations performed by the spreadsheet.

[8] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5-5: DSI Cost Methodology, downloaded from http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/attachment5_5.pdf on 12-18-13.
IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5-2: SDA FGD Cost Methodology, downloaded from http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/attachment5_2.pdf.
IPM Model – Updates to Cost and Performance for APC Technologies, wet FGD Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5-1: SDA FGD Cost Methodology, downloaded from http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/attachment5_1.pdf.
[9] Ibid., p.1: "The data was converted to 2012 dollars based on the Chemical Engineering Plant Index (CEPI) data."

Table 2. Sample DSI Input Parameters

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	**500**	**<---- User Input**
Retrofit Factor	B		**1**	**<---- User Input (An "average" retrofit has a factor = 1.0)**
Gross Heat Rate	C	(Btu/kWh)	**9,500**	**<---- User Input**
SO2 Rate	D	(lb/MMBtu)	**2.00**	**<---- User Input**
Type of Coal	E		**LIG-PRB Blend**	**<--- User Input (PRB, BIT, LIG, or LIG-PRB Blend)**
HHV Bituminous		BTU/lb	**11,000**	**<---- User Input (default is 11,000 Btu/lb if applicable; else no meaning)**
HHV PRB		BTU/lb	**8,400**	**<---- User Input (default is 8,400 Btu/lb if applicable; else no meaning)**
HHV Lignite		BTU/lb	**7,200**	**<---- User Input (default is 7,200 Btu/lb if applicable; else no meaning)**
Percent Lignite if Blended			**50**	**<---- User Input (If Type of Coal = "LIG-PRB Blend," Enter % Lignite. Remainder assumed PRB. If not "LIG-PRB Blend," no meaning)**
Particulate Capture	F		**ESP**	**<---- User Input**
Milled Trona	G		**TRUE**	**<---- User Input**
Removal Target	H	%	**50**	**Maximum Removal Targets:** **Unmilled Trona with an ESP = 65%** **Milled Trona with an ESP = 80%** **Unmilled Trona with a BGH = 80%** **Milled Trona with a BGH = 90%**
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.43	Unmilled Trona with an ESP = If(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = If(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = If(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = If(H<40,0.0160*H,0.208e^(0.0281*H))
Trona Feed Rate	M	(ton/hr)	16.33	(1.2011*10^-6)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	11.65	(0.7387-0.00073696*H/K)*M; Based on a final reaction product of NA2SO4 and unreacted drysorbent as NA2CO3. Waste product adjusted for a maximum of 5% inert in the Trona sorbent.
Include Fly Ash Waste Rate in VOM	P	(ton/hr)	17.05	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV= 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV= 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2 HHV= 7200 For Blend Coal: Ash is proportional to lignite and PRB; Boiler Ash Removal = 0.2; HHV is proportional to lignite and PRB
Include Aux Power in VOM	Q	(%)	0.65	If Milled Trona M*20/A, else M*18/A
Trona Cost	R	($/ton)	**170**	**<---- User Input**
Waste Disposal Cost	S	($/ton)	**50**	**<---- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more difficult to dispose = $100)**
Aux Power Cost	T	($/kWh)	**0.06**	**<---- User Input**
Operating Labor Rate	U	($/hr)	**60**	**<---- User Input (Labor cost including all benefits)**
Interest Rate		(%)	**7**	**<---- User Input**
Equipment Lifetime		(years)	**30**	**<---- User Input**
Gross Load		(MW-hours)	**4,000,000**	**<---- User Input**
SO2 Emission Baseline		(tons/year)	**30,000**	**<---- User Input**

3.1 Selection of DSI Cost Model Input Parameters

Below, we review the DSI Cost Model input values and discuss the procedures we employed in selecting them when constructing the costs for the individual DSI installations. For selected input parameters, we also discuss uncertainties in their values and how we dealt with them. Our overall goal was to select input parameters that would result in a cost that would be a reasonably conservative value. For example, we designed our cost model based on selecting maximum inputs from 2009 – 2013 for the inlet SO_2 rate, the gross heat rate, the gross load, and the percentage lignite even if these values didn't appear in the same year of data. We took this approach in order to ensure that the DSI system was designed to address any operating conditions the unit had experienced in the last five years.

Unit Size (Gross). This parameter is simply the unit size expressed in Megawatts (MW). Although our intent was to use gross and not net values, we are aware that MW values are often reported incorrectly, inconsistently, or the reported values are not specified as to whether they are gross or net values. We therefore invite comments on the accuracy of the values we have used.

Retrofit Factor. The retrofit factor represents a subjective estimation of the average retrofit difficulty. Because we are not aware of any significant retrofit issues at any of the facilities we evaluated, we adopted the default retrofit value of 1.0, which represents an average retrofit difficulty, for all the units we evaluated.

Gross Heat Rate. We calculated the gross heat rate by dividing the Heat Input (MMBtu) by the Gross Load (MW-h), downloaded from our Air Markets Program Data website,[10] and multiplying the result by 1000W/kW to get (BTU/kWh). We chose the gross heat rate to be the maximum annual gross heat rate (Btu/kWh) value from 2009 – 2013 for each unit.

SO_2 Rate. The SO_2 emission rate was calculated from monthly emission data.[11] It was selected as the maximum monthly value from 2009 – 2013. As per the IPM DSI documentation, the SO_2 emission rate has a built-in upper limit of 2.0 lbs/MMBtu. None of the units we evaluated were affected by this limit, although Big Brown's maximum monthly SO_2 emission rate was right at 2.0 lbs/MMBtu.

Type of Coal. The cost algorithms allows the input of three types of coal: bituminous, lignite, and Powder River Basin (PRB) coal from Wyoming. Within the DSI cost algorithms, the type of coal is an input to an interim calculation (P), which is partly dependent on High Heat Value (HHV) of the coal. Also, the cost algorithms assume default values for the HHV of 11,000 Btu/lb for bituminous coal, 8,400 Btu/lb for PRB, and 7,200 Btu/lb for lignite. The interim calculation, P, itself is an input to the variable O&M cost for waste disposal (VOMW).

We note that the cost algorithms are somewhat sensitive to the selection of the type of coal. Therefore, a single coal selection is not appropriate for a few of the facilities for which we are costing DSI and scrubbers, which burn blends of Texas lignite and PRB coals (e.g., Big Brown Units 1, 2 and , Monticello Units 1, 2). In addition, regardless of whether a facility blends coal, we wished to allow the input of more accurate HHV coal values. Therefore, we adjusted the cost algorithms by (1) adding an option for a lignite-PRB coal blend, which if selected requires (2) the input of the percentage of lignite burned (remaining percentage is assumed to be PRB), plus (3) inputs for the HHV of the coals being burned. We select the maximum percent lignite value from 2009 – 2013. We use the three year average HHV values from 2009 – 2013, eliminating the maximum and minimum values. Our adjusted cost model accounts for this information in the calculation of the VOMW.

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[10] http://ampd.epa.gov/ampd/

[11] Ibid.

Particulate Capture. The cost model allows for the input of either an Electrostatic Precipitator (ESP) or a Baghouse (BGH) as the particulate control device. As the IPM DSI documentation states, "Baghouses generally achieve greater SO_2 removal efficiencies than ESPs by virtue of the filter cake on the bags, which allows for longer reaction time between the sorbent solids and the flue gas."[12] For those units that use an ESP along with a polishing baghouse, we assumed that the baghouse would have the capacity to handle the additional particulate matter from the trona by itself. Thus, we assumed the trona would be injected downstream of the ESP and upstream of the baghouse and we modeled the DSI cost on the basis of a baghouse. In all cases we assumed the existing particulate control device has the capacity to handle the additional load due to the addition of the trona. We invite comment from the affected facilities as to whether this assumption is valid.

Milled Trona. As discussed in the IPM DSI documentation, trona is the most commonly used sodium based sorbent material for DSI installations and the DSI cost algorithms assume trona. For a given mass, increasing the surface area of the trona has the effect of improving its ability to remove SO_2 from the flue gas. One common method for increasing the surface area is to mill the trona to a particle size of 30 µm or smaller, using in-line mills. This usually results in slightly higher capital costs, but the overall cost effectiveness of milling the trona improves (lower $/ton), due to the reduction in trona required to achieve a given SO_2 removal target. We assumed that trona would be milled in all cases.

We note, however, that other reagents have important advantages over the use of trona. Hydrated lime, for example, is less sensitive to the conditions of the pneumatic transport air, so less dehumidification or cooling is required for handling; the waste generated by lime injection is not soluble, so normal landfill disposal is feasible without encapsulation, lowering disposal costs; milling is not required; and hydrated lime is usually cheaper.

Removal Target. The removal target is the percentage reduction in SO_2 desired from the SO_2 rate discussed above. The IPM DSI documentation states, "When the sorbent is captured in an ESP, a 40 to 50% SO_2 removal is typically achieved without an increase in particulate emissions. A higher efficiency (70 – 75%) is generally achieved with a baghouse."[13] Solvay Chemicals, Inc., a manufacturer of DSI sorbents, provides general performance information: [14]

[12] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO2 Control Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy, p.1.
[13] Ibid., p.2.
[14] "Dry Sorbent Injection of Sodium Sorbents," presented at the LADCO Lake Michigan Air Directors Consortium, Emission Control and Measurement Technology for Industrial Sources Workshop, March 24, 2010. We note that a number of different DSI trona SO_2 performance curves exist and our use of these curves is as a general reference only.

Figure 1. Typical Trona SO_2 Removal Rates with ESP or Baghouse Installations

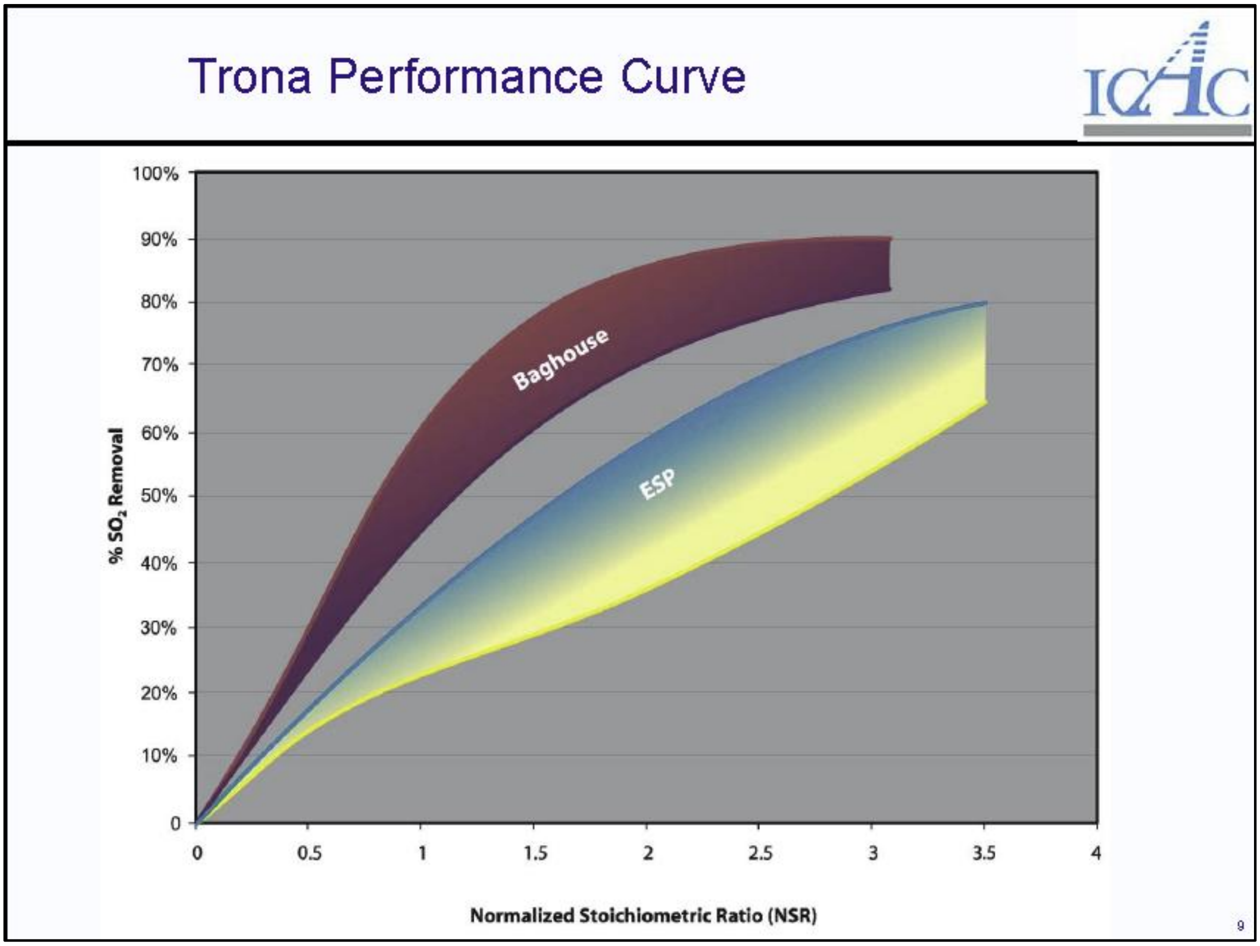

Figure 1 illustrates a number of important concepts concerning the performance potential of DSI:

- SO_2 removal efficiencies for trona DSI installations perform better when a baghouse rather than an ESP particulate control device is employed.
- The Normalized Stoichiometric Ratio (NSR), which is simply a measure of the actual usage needed compared to the theoretical need, governs the SO_2 removal efficiency. In other words, for a given particulate control device, greater SO_2 removal efficiencies require increasingly greater amounts of trona, with diminishing returns.
- A wide range of SO_2 removal efficiency is possible for a given NSR and particulate control device. We interpret this range to be in part dependent on site specific conditions.

We lack the site specific information, which we believe requires an individual performance test, in order to be able to accurately determine the maximum SO_2 removal efficiency for the individual units listed in Table 1. We are aware that a number of the facilities in Table 1 have conducted such testing. However, although we have examined that testing, most of the facilities have claimed it as Confidential Business Information (CBI) and requested protection from public disclosure as provided by 40 C.F.R. Part 2.

However, we nevertheless must evaluate DSI as a viable, proven method of SO_2 control. We must do the same for SO_2 scrubbing, and in so doing, compare the visibility benefits and costs of each technology in order to propose which, if either technology, we should propose for installation due to the RP and/or LTS requirements. We therefore propose the following methodology:

- We will evaluate each unit at its maximum recommended DSI performance level, according to the IPM DSI documentation,[15] assuming milled trona: 80% SO_2 removal for an ESP installation and 90% SO_2 removal for a baghouse installation. This level of control is within that of SO_2 scrubbers, and thus allows a better comparison of the costs of DSI and scrubbers.

- However, (1) we do not know whether a given unit is actually capable of achieving these control levels and (2) we believe it is useful to evaluate lesser levels of DSI control (and correspondingly lower costs). We therefore also evaluate all the units at a DSI SO_2 control level of 50%, which we believe is likely achievable for most units.

- We invite comments on whether particular units have performed DSI testing and have concluded they cannot achieve a SO_2 reduction between 50% and 80/90%. For instance, Luminant states in its response to our Section 114(a) letter regarding its Big Brown and Monticello units:

  > Luminant commissioned the study of dry sorbent injection ("DSI") at these units in 2011. These studies determined that a very high feed rate (in the range of 20-30%) was required to achieve modest SO_2 removal. Further, it was determined that other economic and operational factors make the use of DSI infeasible. For example, sorbent build-up was determined to cause degraded performance of the control equipment over time, as well as significant, repeat down time on a regular basis (i.e., every few days) to remove the buildup. In addition to the high cost of the sorbent required, the disposal and transport of the used sorbent (a Texas Class 1 waste) would result in significant additional cost. Thus, the use of DSI was determined infeasible from both an operational and economic point of view, and further evaluation has been discontinued.

  As a consequence of this statement, which is discussed more fully in the CBI material Luminant has submitted, we have concluded that DSI is not a feasible alternative for the Luminant facilities.

<u>Include Fly Ash Waste Rate in VOM.</u> The cost model allows for the inclusion or exclusion of the fly ash in the Variable O&M costs for waste disposal via a drop down menu. As the IPM

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[15] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO2 Control Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy, p. 7.

DSI documentation notes, when the sodium sorbent (e.g., trona) is captured in the same particulate control device as the fly ash, the resulting waste must be land filled. We are aware that a number of facilities sell their fly ash, and that the addition of trona may render that fly ash unsalable. We chose this option in all cases.

We note that a few of the units we analyzed use an ESP with a polishing baghouse. Such a configuration could allow for the injection of the trona between the ESP and the baghouse, thus allowing for excluding the fly ash from the VOM calculation. This would have the effect of significantly improving the cost effectiveness (reducing the $/ton). However, as the IPM DSI documentation notes, the disposal cost (discussed below) should be increased to account for the additional difficulty in handling the pure sodium waste product. This has the effect of diminishing the cost effectiveness (increasing the $/ton), and erasing much of the gain from excluding the fly ash waste rate from the VOM. We invite the affected facilities to inform us whether they would configure DSI in such a manner.

<u>Include Aux Power in VOM.</u> The cost model allows for the inclusion or exclusion of the additional auxiliary power required for the DSI system to be included in the variable operating costs via a drop down menu. We chose to include this additional auxiliary power in all cases.

<u>Trona Cost.</u> The cost of trona is the largest portion of the variable operating costs. It is partly dependent on the delivery costs. The United States Geological Survey estimates the average 2012 cost of soda ash to be $135/ton F.O.B at the mine or plant.[16] Considering that trona must be delivered from Wyoming to Texas, we contacted Solvay, which is a supplier of Trona, in order to improve this estimate. We were able to get estimated trona costs and some of the estimated freight delivery costs.[17] Trona was quoted as being $100 - $105/ton, so we selected $105/ton. For Big Brown and Welsh, we estimate the freight costs by using the Monticello quote, since all three facilities are in the same regional area of Texas. For Tolk, we estimate the freight cost as the largest value we were quoted, which is that for Coleto Creek.

Table 3: Cost of Trona

Facility	Cost of Trona ($/ton)	Freight by Railroad ($/ton)	Total Cost ($/ton)
Big Brown	$105	$76.25*	$181.25
Coleto Creek	$105	$89.55	$194.55
Monticello	$105	$76.25	$181.25
W. A. Parish	$105	$86.73	$191.73
Tolk	$105	$89.55*	$194.55
Welsh	$105	$76.25*	$181.25

* Estimated

[16] U.S. Department of the Interior U.S. Geological Survey Mineral Commodity Summaries 2013, p. 148. Available at http://minerals.usgs.gov/minerals/pubs/mcs/2013/mcs2013.pdf
[17] Email from Mike Wood to Joe Kordzi, 7-9-2014.

Waste Disposal Cost. The waste disposal cost is the second largest portion of the variable operating costs. The cost model suggests a cost of $50/ton if the trona waste and fly ash are comingled and disposed of together, and $100/ton, if the trona waste is not comingled with the fly ash and is disposed of separately. We assumed the trona waste and the fly ash were comingled and disposed of together for all cases, and therefore set this value to $50/ton. We note that the waste disposal cost is an area in which our cost model could be under predicting the true cost. Because adding trona to the fly ash increases the water solubility of the waste, an upgraded landfill may be required.[18] We invite comments on this issue.

Aux Power Cost. Auxiliary power cost is the additional power required by the DSI control system. It is the smallest portion of the variable operating costs. We note from our examination of CBI material we received in response to our Section 114(a) requests that the true power cost for most if not all of the units we analyze is considerably less than this value. However, the cost model is fairly insensitive to the value used for the auxiliary power cost, and we assumed the default value of $0.06/kWh in all cases.

Operating Labor Rate. The operating labor rate is the largest portion of the fixed operating and maintenance cost. We chose the default value of $60/hour for all cases.

Interest Rate. The interest rate is used in the calculation of the capital recovery factor, which itself is used in the calculation of the annualized capital costs. This input value is not a part of the IPM DSI cost algorithms and was added by us in order to calculate the cost effectiveness in $/ton. For cost analyses related to government regulations, an appropriate "social" interest (discount) rate should be used, unless site specific information is available. We calculated capital recoveries using 3 percent and 7 percent interest rates in determining cost-effectiveness for the Regulatory Impact Analysis (RIA) for the BART Guidelines.[19] Also, a 7 percent interest rate is recommended by Office of Management and Budget.[20]

Equipment Lifetime. The Equipment lifetime is another factor used in the in the calculation of the capital recovery factor. This input value is not a part of the IPM DSI cost algorithms and was added by us in order to calculate the cost effectiveness in $/ton. It represents the actual or service life of the equipment in question. Because a DSI system is relatively simple and reliable, we have no reason to conclude that its service life would be any less than what we typically use for scrubber cost analyses. We therefore adopt that same value here, which is 30 years.

Gross Load. The gross load (MW-h) was obtained from emissions data downloaded from our Air Markets Program Data website.[21] It was selected as the maximum value from 2009 – 2013

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[18] The Ins and Outs of SO_2 Control, Lindsay Morris, Power Engineering, 6-1-2012. "Jonas Klingspor, vice president of business development and marketing for URS, said one potential concern for using DSI systems with trona is the disposal of the product. 'Unless you have a double-lined, capped landfill, the water soluble byproduct may be a serious concern.'"

[19] Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations, EPA-0452/R-05-004 (June 2005).

[20] A 7.0 percent interest rate is recommended by Office of Management and Budget, Circular A-4, Regulatory Analysis, http://www.whitehouse.gov/omb/circulars-a004-a-4/.

[21] http://ampd.epa.gov/ampd/

in order to conservatively maximize the cost. This input value is not a part of the IPM DSI cost algorithms. It was added by us in order to convert the variable and operating costs, which the cost algorithms express in $/MW-h and $/kW-yr, respectively, into dollars which are subsequently used in calculating the cost effectiveness in dollars per ton of SO_2 removed ($/ton).

SO_2 Emission Baseline. The SO_2 emission baseline is calculated from emissions data downloaded from our Air Markets Program Data website.[22] It was selected as the 2009 – 2013 five year average of the SO_2 annual emissions, excluding the maximum and minimum values. This input value is not a part of the IPM DSI cost algorithms. It was added by us in order to calculate the annual SO_2 emission reduction from the installation of DSI, which itself is an input to the cost effectiveness in $/ton. We concluded that using this kind of an average was a reasonable compromise between simply selecting the maximum value from 2009 – 2013, or using the average of the values from 2009 – 2013.

3.2 DSI Cost Model Output

A sample of the IPM DSI cost model output is depicted below in Table 4. The cost algorithms calculate the Capital, Engineering and Construction Cost (CECC) and the fixed and variable operating costs (FOM and VOM, respectively). Following this, we add a calculation for the capital recovery factor, based on the interest rate and the Equipment lifetime, and use it to annualize the CECC. In so doing, we exclude any Allowance for Funds Used During Construction (AFUDC) and "owner's costs."[23] To the annualized CECC, we add the FOM and VOM to arrive at the total annualized costs. Lastly, we divide this figure by the SO_2 emissions reduction to calculate the cost effectiveness in $/ton.

[22] Ibid.

[23] We exclude any AFUDC and "owner's costs" from regional haze control cost calculations, as they are disallowed by the "overnight" cost method used in the Control Cost Manual. In this case, however, AFUDC is assumed by the cost algorithms to be zero anyway, since a DSI project is expected to be completed within one year.

Table 4. Sample DSI Output

Capital Cost Calculation		Explanation of Calculation
		Includes: equipment, installation, buildings, foundations, electrical, and retrofit difficulty.
BM ($)	$18,348,000	Base DSI module includes all equipment from unloading to injection.
BM ($/kW)	37	Base module cost per kW
Total Project Cost		
A1	$917,000	Engineering and construction management costs
A2	$917,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc..
A3	$917,000	Contractor profit and fees
CECC($)	**$21,099,000**	Capital, engineering and construction cost subtotal
CECC($/kW)	**42**	Capital, engineering and construction cost subtotal per kW
B1	$1,055,000	Owners costs including "home office" costs (owner engineering, management, and procurement activities)
TPC ($)	**$22,154,000**	Total project cost without AFUDC
TPC ($/kw)	**44**	Total project cost per kW without AFUDC
B2	$0	AFUDC (zero for less than 1 year engineering and construction cycles)
TPC ($)	**$22,154,000**	Total project cost
TPC ($/kw)	**44**	Total project cost per kW
Fixed O&M Cost		
FOMO ($/kW yr)	0.50	Fixed O&M additional operating labor costs. Based on two additional operators.
FOMM ($/kW yr)	0.37	Fixed O&M maintenance material and labor costs
FOMA ($/kW yr)	0.02	Fixed O&M additional addministrative labor costs
FOM ($/kW yr)	**0.89**	Total Fixed O&M costs
Variable O&M		
VOMR ($/MWh)	5.55	Variable O&M costs for trona reagent
VOMW ($/MWh)	2.87	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the
VOMP ($/MWh)	0.39	Variable O&M costs for additional auxillary power required (refer to Aux Power % above)
VOM ($/MWh)	**8.82**	Total variable O&M costs
Annualization		
Capital, engineering and construction cost	$21,099,000	Excludes owner's costs and AFUDC
Capital Recovery factor	0.0806	
Annualized capital costs	$1,700,293	
Variable operating costs	$35,260,822	VOM*(Gross Load)
Fixed operating costs	$404,356	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)
Total annualized costs	**$37,365,470**	
SO2 emissions reduction (tons)	15,000	H/(100%)*(SO2 emission baseline)
$/ton	**2,491**	

3.3 Summary of DSI Cost Model Results

Below in Table 5 is a summary of our DSI cost model results:

Table 5. Summary of DSI Cost Model Results

Facility	Unit	DSI Control (%)	DSI SO2 Reduction (tpy)	DSI Capital Cost	DSI Annualized Capital Cost	DSI Variable Operating Cost	DSI Fixed Operating Cost	DSI Total Annualized Cost	DSI Cost Effectiveness ($/ton)
Big Brown	1	50.00	15,334	$19,096,000	$1,538,878	$32,128,615	$419,378	$34,086,871	$2,223
		90.00	27,600	$33,357,000	$2,688,121	$79,452,946	$543,175	$82,684,241	$2,996
	2	50.00	15,407	$19,035,000	$1,533,962	$31,959,458	$416,402	$33,909,822	$2,201
		90.00	27,733	$32,965,000	$2,656,531	$78,456,412	$536,643	$81,649,586	$2,944
Coleto Creek	1	50.00	8,030	$15,888,000	$1,280,357	$20,731,452	$404,410	$22,416,218	$2,792
		90.00	14,453	$21,863,000	$1,761,861	$47,781,846	$457,979	$50,001,685	$3,460
Monticello	1	50.00	8,933	$17,137,000	$1,381,009	$22,609,610	$374,199	$24,364,819	$2,728
		90.00	16,079	$23,580,000	$1,900,227	$52,664,972	$426,218	$54,991,417	$3,420
	2	50.00	8,215	$17,057,000	$1,374,562	$23,585,904	$390,904	$25,351,370	$3,086
		90.00	14,786	$23,468,000	$1,891,202	$54,514,200	$445,087	$56,850,489	$3,845
Tolk	171B	50.00	5,016	$13,938,000	$1,123,213	$13,968,324	$374,040	$15,465,578	$3,084
		90.00	9,028	$19,179,000	$1,545,567	$30,461,398	$419,465	$32,426,429	$3,592
	172B	50.00	5,517	$13,873,000	$1,117,975	$14,115,709	$366,470	$15,600,155	$2,828
		90.00	9,931	$19,090,000	$1,538,394	$30,036,649	$410,837	$31,985,880	$3,221
W A Parish	WAP5	50.00	7,079	$15,227,000	$1,227,089	$16,546,703	$338,198	$18,111,990	$2,559
		90.00	12,741	$20,953,000	$1,688,527	$36,091,083	$381,772	$38,161,382	$2,995
	WAP6	50.00	7,654	$15,934,000	$1,284,064	$19,027,337	$349,036	$20,660,436	$2,699
		90.00	13,776	$21,924,000	$1,766,776	$42,315,954	$395,356	$44,478,086	$3,229
	WAP7	50.00	6,168	$14,641,000	$1,179,866	$15,752,870	$368,792	$17,301,527	$2,805
		90.00	11,102	$20,145,000	$1,623,413	$34,555,902	$415,087	$36,594,402	$3,296
Welsh	1	50.00	4,042	$14,888,000	$1,199,770	$13,501,650	$325,118	$15,026,538	$3,718
		80.00	6,467	$18,901,000	$1,523,164	$24,115,114	$354,687	$25,992,966	$4,019
	2	50.00	4,128	$14,775,000	$1,190,664	$13,390,807	$325,342	$14,906,814	$3,611
		80.00	6,605	$18,758,000	$1,511,640	$23,755,748	$354,778	$25,622,166	$3,879
	3	50.00	4,305	$15,023,000	$1,210,650	$14,337,927	$336,087	$15,884,663	$3,690
		80.00	6,887	$19,071,000	$1,536,863	$25,628,127	$366,841	$27,531,831	$3,998

3.4 Discussion of DSI Cost Model Results

Some observations are apparent from the DSI cost model results displayed above:

- The vast majority of the total annualized cost of DSI is due to the variable operating cost, VOM. This is due to the relatively low capital cost of the equipment, and the relatively high cost of the trona.
- Unlike the cost effectiveness of scrubbers, which we will discuss below, for a given facility, the cost effectiveness of DSI worsens (higher $/ton) with increasing control levels. This is due to the inefficient use of the sorbent in DSI systems. Unlike scrubbers, in which the reaction of the reagent and the SO_2 in the exhaust gas occurs within a large vessel (e.g., an absorber), which can be highly controlled, DSI lacks an absorber. Greater SO_2 removal efficiencies require increasingly greater amounts of trona, with diminishing returns.
- For a given level of control, the cost effectiveness of DSI generally improves as the tonnage of SO_2 removal increases.

4 Overview of SDA Cost Model Input Parameters

Table 6, below, is a depiction of the input section of the SDA cost spreadsheet. Sample input parameters for the SDA cost calculation are represented by the yellow highlighted cells. The input values designated “A” through “T” have the same meaning as those contained within the documentation for the IPM SDA cost algorithms (hereafter referred to as the “IPM SDA documentation”) referenced above. The last four input values, (i. e., Interest rate, Equipment Lifetime, Gross Load, and Baseline) were added by us in order to calculate the annualized costs per ton of SO_2 removed ($/ton). Those cells that are not highlighted in yellow are interim calculations performed by the spreadsheet.

Table 6. Sample SDA Input Parameters

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	**519.9**	**<--- User Input (Greater than 50 MW)**
Retrofit Factor	B		**1**	**<--- User Input (an "average" retrofit has a factor =1.0)**
Gross Heat Rate	C	(Btu/kWh)	**10,426**	**<--- User Input**
SO2 Rate	D	(lb/MMBtu)	**0.53**	**<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)**
Type of Coal	E		**PRB**	**<--- User Input (PRB, BIT, or LIG)**
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		1.0426	C/10000
Heat Input	H	(Btu/Hr)	5,420,477,400	A*C*1000
Operating SO_2 Removal	J	(%)	**88.68**	**<--- User Input (Used to adjust actual operating costs)**
Lime Rate	K	(Ton/Hr)	2	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(Ton/Hr)	5	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Include Aux Power in VOM	M	(%)	1.43	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	(1000 gph)	32	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/Ton)	**125**	**<--- User Input**
Waste Disposal Cost	Q	($/Ton)	**30**	**<--- User Input**
Aux Power Cost	R	($/kWh)	**0.06**	**<--- User Input**
Makeup Water Cost	S	($/1000[gal])	**1**	**<--- User Input**
Operating Labor Rate	T	($/hr)	**60**	**<--- User Input (Labor cost including all benefits)**
Elevation adjustment if > 500 Feet		(feet)	**0**	**<--- User Input (no entry needed if less than 500 feet)**
Interest Rate		(%)	**7**	**<---- User Input**
Equipment Lifetime		(years)	**30**	**<---- User Input**
Gross Load		(MW-hours)	**3,931,843**	**<---- User Input**
SO2 Emission Baseline		(tons/year)	**8,609**	**<---- User Input**

4.1 Selection of SDA Cost Model Input Parameters

Below, for those input values that are different than our DSI cost model, we review the SDA cost model input values and discuss the procedures we employed in selecting them when developing the cost estimates for the individual SDA installations.

Type of Coal: Unlike the DSI cost algorithms discussed above, the SDA cost algorithms are relatively insensitive to the type of coal. For instance, simply changing the type of coal from lignite to PRB for Big Brown Unit 1 results in an improvement in the cost effectiveness (lower $/ton) of less than 1%. Therefore, for those facilities that burn a mixture of lignite and PRB, we are simply assuming they burn lignite for the purposes of costing a SDA system.

Operating SO_2 Removal. The operating SO_2 removal is the percentage reduction in SO_2 desired from the SO_2 rate. The IPM SDA Documentation states: “The curve fit was set to represent proprietary in-house cost data of a "typical" SDA FGD retrofit for removal of 95% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufacturers of SDA FGD systems, are 0.06 lb/MMBtu.” As with our Oklahoma FIP,[24] we have assumed a level of control equal to 95%, unless that level of control would fall below an outlet SO_2 level of 0.06 lb/MMBtu, in which case, we assume the percentage of control equal to 0.06 lbs/MMBtu.

Lime Cost. The cost of lime is the largest portion of the variable operating costs. At most dry scrubber facilities, the lime reagent is produced by onsite slaking of quicklime (calcium oxide) to produce a slurry of solid hydrated lime (calcium hydroxide) particles.[25] Therefore, we assume in our cost model that quicklime is delivered to the facility where it is then slaked onsite, and that this cost is a part of the “base reagent preparation and waste recycle/handling” cost module.[26] The USGS estimates the average 2012 cost of quicklime to be $116/ton at the lime plant.[27] Although we do not have lime pricing available for Texas, lime is widely available within the State and we expect delivery charges to be minimal. Consequently, we consider the cost algorithm default cost for delivered lime of $125/ton to be reasonable, and we have adopted it for all cases. We invite the affected facilities to provide comment on this assumption.

Waste Disposal Cost. The waste disposal cost is the second largest portion of the variable operating costs. The cost model default is $30/ton and we have adopted it for all cases.

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[24] As discussed previously in our TSD and elsewhere in this notice and the Supplemental RTC, control efficiencies reasonably achievable by dry scrubbing and wet scrubbing were determined to be 95% and 98% respectively. 76 FR 81742.

[25] Primex Process Specialists. “Optimizing Scrubber Performance,” p. 3. Available at http://www.primexprocess.com/pdf/Paper_4.pdf

[26] IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final, March 2013. Sargent & Lundy, p. 3

[27] U.S. Department of the Interior U.S. Geological Survey Mineral Commodity Summaries 2013, p. 92. Available at http://minerals.usgs.gov/minerals/pubs/mcs/2013/mcs2013.pdf

Elevation Adjustment. The IPM SDA documentation states that the cost methodology is based on a unit located within 500 feet of sea level:[28]

> The actual elevation of the site should be considered separately and factored into the cost due to the effects on the flue gas volume. The base absorber island and balance of plant costs are directly impacted by the site elevation. These two base cost modules should be increased based on the ratio of the atmospheric pressure between sea level and the unit location. As an example, a unit located 1 mile above sea level would have an approximate atmospheric pressure of 12.2 psia. Therefore, the base absorber island and balance of plant costs should be increased by:
>
> 14.7 psia/12.2 psia = 1.2 multiplier to the base absorber island and balance of plant costs.

Although the cost algorithms call for this correction, no implementation was provided. Consequently, we included this atmospheric pressure adjustment in our SDA cost model by incorporating an atmospheric pressure change with elevation calculation provided by NASA.[29] In order to utilize this calculation, we constructed Table 7, below, which uses the average of the latitude and longitude of the stack locations. We entered these coordinates into an online service[30] that returns the elevation above sea level.

Table 7. Elevation of Sources undergoing RP and LTS analyses

	Latitude	Longitude	Elevation
Big Brown	31.8200	-96.0552	334.6
Coleto Creek	28.7108	-97.2139	108.3
San Miguel	28.7072	-98.4722	318.2
Martin Lake	32.2596	-94.5707	324.8
Monticello	33.0913	-95.0376	383.9
Limestone	31.4195	-96.2539	436.4
Sandow 4	30.5658	-97.0631	492.1
Tolk	34.1797	-102.5750	3753.3
W. A. Parish	29.4792	-95.6324	78.7
Welsh	33.0564	-94.8458	377.3

28 IPM SDA documentation, p. 2.
29 http://exploration.grc.nasa.gov/education/rocket/atmosmet.html. It should be noted that in addition to the NASA algorithm, this calculation requires converting the input feet to meters (multiplying elevation*0.3048) and K-Pa to psi (multiplying the calculation by 0.145038).
30 http://www.earthtools.org/webservices.htm#height

As can be seen from Table 7, only the Tolk facility is located at an elevation that exceeds 500 feet above sea level, and thus requires an elevation adjustment, which we included in our SDA cost model for this facility. This correction had the effect of worsening the cost effectiveness (increasing the $/ton) for Tolk by approximately 5%.

4.2 SDA Cost Model Output

A sample of the IPM SDA cost model output is depicted below in Table 8. As with our DSI cost model, the cost algorithms calculate the CECC and the FOM and VOM, and we add a calculation for the capital recovery factor, based on the interest rate and the Equipment lifetime, and use it to annualize the CECC. We exclude AFUDC and "owner's costs." To the annualized CECC, we add the FOM and VOM to arrive at the total annualized costs. Lastly, we divide this figure by the SO_2 emissions reduction to calculate the cost effectiveness in $/ton.

Table 8. Sample SDA Output

Capital Cost Calculation		Explanation of Calculation
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit difficulty
BMR($)	51,886,000	Base module absorber island cost
BMF($)	31,337,000	Base module reagent preparation and waste recycle/handling cost
BMB($)	73,422,000	Base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.)
BMBA($)	73,422,000	Adjustment to base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.), if elevation is greater than 500 feet. See page 2 of the S&L documentation.
BM($)	**156,645,000**	Total Base module cost including retrofit factor
BM($/kW)	313	Base module cost per kW
Total Project Cost		
A1	15,665,000	Engineering and Construction Mnagement costs
A2	15,665,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3	15,665,000	Contractor profit and fees.
CECC ($)	**203,640,000**	Capital, engineering and construction cost subtotal
CECC($/kW)	**407**	Capital, engineering and construction cost subtotal per kW
B1	10,182,000	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC' ($)	**213,822,000**	Total project cost without AFUDC
TPC' ($/kw)	**428**	Total project cost per kW without AFUDC
B2	21,382,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($)	**235,204,000**	Total Project Cost (including AFUDC and owner's costs)
TPC ($/kW)	**470**	Total Project Cost per kW (including AFUDC and owner's costs)
Fixed O&M Cost		
FOMO ($/kW-yr)	2.00	Fixed O&M additional operating labor costs. Based on eight additional operators.
FOMM ($/kW-yr)	4.70	Fixed O&M costs for waste disposal
FOMA ($/kW-yr)	0.12	Fixed O&M additional administrative labor costs
FOM ($/kW-yr)	**6.81**	Total Fixed O&M costs
Variable O&M Cost		
VOMR ($/MWh)	1.81	Variable O&M costs for lime reagent
VOMW ($/MWh)	0.96	Variable O&M costs for waste disposal
VOMP ($/MWh)	0.81	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh)	0.06	Variable O&M costs for makeup water
VOM ($/MWh)	**3.64**	Total Variable O&M Costs
Annualization		
Capital, engineering and construction cost	$203,640,000	Excludes owner's costs and AFUDC
Capital Recovery factor	0.0806	
Annualized capital costs	$16,410,615	
Variable operating costs	$15,645,084	VOM*(Gross Load)
Fixed operating costs	$3,340,299	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)
Total annualized costs	**$35,395,997**	
SO2 emissions reduction (tons)	29,061	J/(100%)*(SO2 emission baseline)
$/ton	**1,218**	

4.3 Summary of SDA Cost Model Results

Below in Table 9 is a summary of our SDA cost model results:

Table 9. Summary of SDA Cost Model Results

Facility	Unit	SDA Control (%)	SDA SO_2 Reduction (tpy)	SDA Capital Cost	SDA Annualized Capital Cost	Variable Operating Cost	SDA Fixed Operating Cost	SDA Total Annualized Cost	SDA Cost Effectiveness ($/ton)
Big Brown	1	95.0	29,134	$226,656,000	$18,265,392	$18,213,992	$3,625,183	$40,104,566	$1,377
	2	95.0	29,273	$229,544,000	$18,498,125	$18,050,505	$3,637,262	$40,185,893	$1,373
Coleto Creek	1	93.5	15,012	$240,408,000	$19,373,616	$12,085,110	$3,908,190	$35,366,916	$2,356
Monticello	1	95.0	16,972	$224,262,000	$18,072,468	$12,736,712	$3,345,752	$34,154,932	$2,012
	2	95.0	15,608	$227,409,000	$18,326,073	$13,320,394	$3,536,557	$35,183,025	$2,254
Tolk	171B	91.7	9,195	$218,306,000	$17,592,495	$8,102,576	$3,523,765	$29,218,836	$3,178
	172B	90.8	10,015	$226,957,000	$18,289,648	$8,177,697	$3,555,264	$30,022,609	$2,998
W A Parish	WAP5	92.5	13,095	$240,112,000	$19,349,763	$9,306,997	$3,313,891	$31,970,651	$2,441
	WAP6	93.1	14,251	$248,503,000	$20,025,963	$10,741,546	$3,452,649	$34,220,158	$2,401
	WAP7	92.7	11,432	$211,443,000	$17,039,431	$8,868,427	$3,342,164	$29,250,022	$2,559
Welsh	1	88.7	7,169	$201,549,000	$16,242,109	$5,934,757	$2,832,919	$25,009,785	$3,489
	2	88.2	7,285	$202,108,000	$16,287,157	$5,910,741	$2,847,620	$25,045,518	$3,438
	3	88.7	7,634	$204,177,000	$16,453,890	$6,313,169	$2,946,089	$25,713,148	$3,368

4.4 Summary of SDA Cost Model Results

Some observations are apparent from the SDA cost model results displayed above:

- In contrast to our DSI cost model results, a greater portion of the total annualized cost of SDA is due to the annualized capital costs and the annualized capital cost is greater than the total operating cost in most cases. However, the annualized capital costs and the operating costs are much closer in magnitude.
- Unlike the cost effectiveness of DSI, the cost effectiveness of SDA improves (lower $/ton) with increasing control levels.

5 Overview of Wet FGD Cost Model Input Parameters

Table 10, below, is a depiction of the input section of the wet FGD cost spreadsheet. Sample input parameters for the wet FGD cost calculation are represented by the yellow highlighted cells. The input values designated “A” through “T” have the same meaning as those contained within the documentation for the IPM wet FGD cost algorithms (hereafter referred to as the “IPM wet FGD documentation”) referenced above. The last four input values, (i. e., Interest rate, Equipment Lifetime, Gross Load, and Baseline) were added by us in order to calculate the annualized costs per ton of SO_2 removed ($/ton). Those cells that are not highlighted in yellow are interim calculations performed by the spreadsheet.

Table 10. Sample Wet FGD Input Parameters

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	**500**	**<--- User Input (Greater than 50 MW)**
Retrofit Factor	B		**1**	**<--- User Input (An "average" retrofit has a factor =1.0)**
Gross Heat Rate	C	(Btu/kWh)	**9,500**	**<--- User Input**
SO2 Rate	D	(lb/MMBtu)	**3.00**	
Type of Coal	E		**BIT**	**<--- User Input (PRB, BIT, or LIG)**
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/Hr)	4,750,000,000	A*C*1000
Operating SO_2 Removal	J	(%)	**95.00**	**<--- User Input (Used to adjust actual operating costs)**
Design Limestone Rate	K	(Ton/Hr)	12	(17.52*A*D*G/2000 (Based on 98% SO2 removal)
Design Waste Rate	L	(Ton/Hr)	23	1.811*K (Based on 98% SO2 removal)
Include Aux Power in VOM	M	(%)	1.59	(1.05e^(0.155*D+1.3))*F*G
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/Ton)	**30**	**<--- User Input**
Waste Disposal Cost	Q	($/Ton)	**30**	**<--- User Input**
Aux Power Cost	R	($/kWh)	**0.06**	**<--- User Input**
Makeup Water Cost	S	($/1000[gal])	**1**	**<--- User Input**
Operating Labor Rate	T	($/hr)	**60**	**<--- User Input (Labor cost including all benefits)**
Elevation adjustment if > 500 Feet		(feet)	**0**	**<--- User Input (no entry needed if less than 500 feet)**
Interest Rate		(%)	**7**	**<---- User Input**
Equipment Lifetime		(years)	**30**	**<---- User Input**
Gross Load		(MW-hours)	**4,295,229**	**<---- User Input**
SO2 Emission Baseline		(tons/year)	**30,591**	**<---- User Input**

5.1 Selection of Wet FGD Cost Model Input Parameters

Below, for those input values that are different than our SDA cost model, we review the wet FGD Cost Model input values and discuss the procedures we employed in selecting them when developing the cost estimates for the individual wet FGD installations.

Operating SO_2 Removal. The operating SO_2 removal is the percentage reduction in SO_2 desired from the SO_2 rate. The IPM wet FGD Documentation states: "The least squares curve fit of the data was defined as a "typical" wet FGD retrofit for removal of 98% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufacturers of wet FGD systems, are 0.04 lb/MMBtu." As we established in our Oklahoma

FIP,[31] this level of control is achievable with wet FGD. We have therefore assumed a level of control equal to 98%, unless that level of control would fall below an outlet SO_2 level of 0.04 lb/MMBtu, in which case, we assume the percentage of control equal to 0.04 lbs/MMBtu.

Limestone Cost. Unlike the DSI and SDA cost algorithms, the wet FGD cost algorithms are fairly insensitive to the cost of the reagent – limestone. We note that the cost of limestone is partly dependent on the delivery cost, but limestone is widely available within Texas. Consequently, we consider the cost algorithm default cost for delivered lime of $30/ton to be reasonable, and we have adopted it for all cases.

Elevation Adjustment. Our wet FGD cost model incorporates the same elevation adjustment discussed above with regard to the SDA cost model. Again, only the Tolk facility required this adjustment, which we incorporated into our cost model for this facility. This correction had the effect of worsening the cost effectiveness for Tolk (increasing the $/ton) by approximately 6%.

Wastewater Treatment. The IPM wet FGD documentation states:

> The evaluation includes a user selected option for a wastewater treatment facility. The base capital cost includes minor physical and chemical wastewater treatment. However, in the future more extensive wastewater handling may be required. Although an option for wastewater treatment is provided, no logic has been developed to accommodate the additional wastewater treatment costs.

Consequently, our cost model incorporates minor physical and chemical wastewater treatment. We invite comment from the affected facilities as to whether they believe more extensive wastewater treatment would be required for their facility, and if so, to provide an estimate of that cost.

5.2 Wet FGD Cost Model Output

A sample of the IPM wet FGD cost model output is depicted below in Table 11. As with our DSI and SDA cost models, the cost algorithms calculate the CECC and the FOM and VOM, and we add a calculation for the capital recovery factor, based on the interest rate and the Equipment lifetime, and use it to annualize the CECC. We exclude AFUDC and "owner's costs." To the annualized CECC, we add the FOM and VOM to arrive at the total annualized costs. Lastly, we divide this figure by the SO_2 emissions reduction to calculate the cost effectiveness in $/ton.

[31] As discussed previously in our TSD and elsewhere in this notice and the Supplemental RTC, control efficiencies reasonably achievable by dry scrubbing and wet scrubbing were determined to be 95% and 98% respectively. 76 FR 81742.

Table 11. Sample Wet FGD Output

Capital Cost Calculation		Explanation of Calculation
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit difficulty
BMR($)	48,869,000	Base absorber island cost
BMF($)	23,674,000	Base reagent preparation and waste recycle/handling cost
BMW($)	14,536,000	Base reagent
BMB($)	89,730,000	Base balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.)
BMBA($)	89,730,000	Adjustment to base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.), if elevation is greater than 500 feet. See page 2 of the S&L documentation.
BM($)	**176,809,000**	Total Base module cost including retrofit factor
BM($/kW)	354	Base cost per kW
Total Project Cost		
A1	17,681,000	Engineering and Construction Mnagement costs
A2	17,681,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3	17,681,000	Contractor profit and fees.
CECC ($)	**229,852,000**	Capital, engineering and construction cost subtotal
CECC($/kW)	**460**	Capital, engineering and construction cost subtotal per kW
B1	11,493,000	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC' ($)	**241,345,000**	Total project cost without AFUDC
TPC' ($/kw)	**483**	Total project cost per kW without AFUDC
B2	24,135,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($)	**265,480,000**	Total Project Cost (including AFUDC and owner's costs)
TPC ($/kW)	**531**	Total Project Cost per kW (including AFUDC and owner's costs)
Fixed O&M Cost		
FOMO ($/kW-yr)	3.00	Fixed O&M additional operating labor costs. IF MW > 500, then 16 operators, else 12 operators
FOMM ($/kW-yr)	5.30	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW-yr)	0.15	Fixed O&M additional administrative labor costs
FOM ($/kW-yr)	**8.45**	Total Fixed O&M costs
Variable O&M Cost		
VOMR ($/MWh)	0.73	Variable O&M costs for limestone reagent
VOMW ($/MWh)	1.31	Variable O&M costs for waste disposal
VOMP ($/MWh)	0.95	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh)	0.08	Variable O&M costs for makeup water
VOM ($/MWh)	**3.07**	Total Variable O&M Costs
Annualization		
Capital, engineering and construction cost	$229,852,000	Excludes owner's costs and AFUDC
Capital Recovery factor	0.0806	
Annualized capital costs	$18,522,946	
Variable operating costs	$13,184,075	VOM*(Gross Load)
Fixed operating costs	$4,144,689	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)
Total annualized costs	**$35,851,710**	
SO2 emissions reduction (tons)	29,061	J/(100%)*(SO2 emission baseline)
$/ton	**1,234**	

5.3 Summary of Wet FGD Cost Model Results

Below in Table 12 is a summary of our wet FGD cost model results:

Table 12. Summary of Wet FGD Cost Model Results

Facility	Unit	Wet FGD Control (%)	Wet FGD SO_2 Reduction (tpy)	Wet FGD Capital Cost	Wet FGD Annualized Capital Cost	Wet FGD Variable Operating Cost	Wet FGD Fixed Operating Cost	Wet FGD Total Annualized Cost	Wet FGD cost Effectiveness ($/ton)
Big Brown	1	98.0	30,054	$256,032,000	$20,632,698	$12,098,348	$4,977,952	$37,708,999	$1,255
	2	97.9	30,169	$259,141,000	$20,883,241	$12,041,741	$4,984,725	$37,909,708	$1,257
Coleto Creek	1	95.7	15,361	$262,435,000	$21,148,693	$8,630,180	$5,218,106	$34,996,979	$2,278
Monticello	1	97.0	17,328	$250,804,000	$20,211,392	$8,773,313	$4,573,464	$33,558,169	$1,937
	2	96.8	15,907	$254,177,000	$20,483,210	$9,216,786	$4,823,887	$34,523,884	$2,170
Tolk	171B	94.4	9,474	$243,048,000	$19,586,364	$5,945,142	$4,821,258	$30,352,765	$3,204
	172B	93.8	10,355	$252,559,000	$20,352,821	$6,066,412	$4,838,067	$31,257,301	$3,019
W A Parish	WAP5	95.0	13,449	$260,195,000	$20,968,179	$6,750,666	$4,405,963	$32,124,808	$2,389
	WAP6	95.4	14,603	$270,350,000	$21,786,534	$7,718,960	$4,580,211	$34,085,705	$2,334
	WAP7	95.1	11,733	$233,698,000	$18,832,881	$6,415,025	$4,573,221	$29,821,127	$2,542
Welsh	1	92.5	7,474	$221,282,000	$17,832,321	$4,496,593	$3,887,380	$26,216,294	$3,508
	2	92.2	7,608	$221,821,000	$17,875,757	$4,495,716	$3,905,333	$26,276,805	$3,454
	3	92.5	7,959	$224,298,000	$18,075,369	$4,783,305	$4,036,716	$26,895,390	$3,379

5.4 Summary of Wet FGD Cost Model Results

Some observations are apparent from the wet FDG cost model results displayed above:

- As with our SDA cost model results, the majority of the total annualized cost of SDA is due to the annualized capital costs. However, the annualized capital costs is much greater than the operational costs. This is due to the slightly higher capital cost of the equipment and the lower cost of reagent (limestone versus lime), in relation to SDA.
- As with our SDA cost model, the cost effectiveness of wet FGD improves (lower $/ton) with increasing control levels.

Table 13 compares the capital cost and cost effectiveness of both technologies:

Table 13. Capital cost and cost effectiveness of wet FGD versus SDA

Facility	Unit	Capital Cost SDA	Capital Cost Wet FGD	% Difference Capital Cost Wet FGD over SDA	$/ton SDA	$/ton Wet	% Difference $/ton Wet FGD over SDA
Big Brown	1	$226,656,000	$256,032,000	12.96	$1,377	$1,255	-8.9
	2	$229,544,000	$259,141,000	12.89	$1,373	$1,257	-8.5
Coleto Creek	1	$240,408,000	$262,435,000	9.16	$2,356	$2,278	-3.3
Monticello	1	$224,262,000	$250,804,000	11.84	$2,012	$1,937	-3.8
	2	$227,409,000	$254,177,000	11.77	$2,254	$2,170	-3.7

Tolk	171B	$218,306,000	$243,048,000	11.33	$3,178	$3,204	0.8
	172B	$226,957,000	$252,559,000	11.28	$2,998	$3,019	0.7
W A Parish	WAP5	$240,112,000	$260,195,000	8.36	$2,441	$2,389	-2.2
	WAP6	$248,503,000	$270,350,000	8.79	$2,401	$2,334	-2.8
	WAP7	$211,443,000	$233,698,000	10.53	$2,559	$2,542	-0.7
Welsh	1	$201,549,000	$221,282,000	9.79	$3,489	$3,508	0.5
	2	$202,108,000	$221,821,000	9.75	$3,438	$3,454	0.5
	3	$204,177,000	$224,298,000	9.85	$3,368	$3,379	0.3

- The capital cost of wet FGD is higher than SDA by approximately 8 – 13%. However, wet FGD delivers a significant improvement in the cost effectiveness for a number of the units, increasing as the tonnage of SO_2 removal increases This is mainly due to the greater level of control (98% maximum versus 95% maximum) of wet FGD over SDA, which tends to offset the additional cost of wet FGD. The exceptions to this are the Tolk and Welsh units, which burn 100% PRB coal. This is not unexpected as many EGUs that burn PRB coal and are equipped with SO_2 scrubbers have installed SDA scrubbers.

6 Upgrading Existing Scrubber Efficiencies

In Sections 3, 4, and 5, above, for those facilities with no SO_2 control, we contrasted the cost of DSI, SDA, and wet FGD. We then compared those costs to the visibility benefit from those controls from our visibility projection modeling, and we propose a RP and LTS determination. Here, we conduct similar analyses for those units listed in Table 1 with an existing SO_2 scrubber in order to determine if cost effective scrubber upgrades are available. Because all of the scrubber systems we evaluate are wet scrubbers, we limit our analyses of scrubber upgrades to wet scrubbers.

We proceed by first presenting information concerning the kinds of options generally available to facilities for upgrading their existing scrubbers. Following this, to the extent possible, we review all of the information we have at our disposal regarding the status of the existing scrubbers for each unit. This includes any upgrades the facility may have already installed. Although some of this information has been gleaned from public sources of information, much of it was collected as a result of our information collection effort. The companies that have supplied this information have asserted a Confidential Business Information (CBI) claim for much of it, as provided in 40 C.P.R. § 2.203(b). We therefore must redact any CBI information we utilize in our analyses, or otherwise disguise it so that it cannot be traced back to its specific source. Similar to our DSI, SDA, and wet FGD analyses we then contrast the cost of the various options for upgrading those scrubbers. Following this, we compare those costs to the visibility benefit from those controls from our visibility projection modeling, and propose a RP and LTS determination.

We have long recognized that existing underperforming SO_2 scrubbers are likely capable of being upgraded to much higher removal efficiencies. For example, we made this statement in the BART rule:[32]

> For those BART-eligible EGUs with preexisting post-combustion SO_2 controls achieving removal efficiencies of at least 50 percent, your BART determination should consider cost effective scrubber upgrades designed to improve the system's overall SO_2 removal efficiency. There are numerous scrubber enhancements available to upgrade the average removal efficiencies of all types of existing scrubber systems. We recommend that as you evaluate the definition of ''upgrade,'' you evaluate options that not only improve the design removal efficiency of the scrubber vessel itself, but also consider upgrades that can improve the overall SO_2 removal efficiency of the scrubber system. Increasing a scrubber system's reliability, and conversely decreasing its downtime, by way of optimizing operation procedures, improving maintenance practices, adjusting scrubber chemistry, and increasing auxiliary equipment redundancy, are all ways to improve average SO_2 removal efficiencies.
>
> We recommend that as you evaluate the performance of existing wet scrubber systems, you consider some of the following upgrades, in no particular order, as potential scrubber upgrades that have been proven in the industry as cost effective means to increase overall SO_2 removal of wet systems:
>
> (a) Elimination of Bypass Reheat;
> (b) Installation of Liquid Distribution Rings;
> (c) Installation of Perforated Trays;
> (d) Use of Organic Acid Additives;
> (e) Improve or Upgrade Scrubber Auxiliary System Equipment;
> (f) Redesign Spray Header or Nozzle Configuration.
>
> We recommend that as you evaluate upgrade options for dry scrubber systems, you should consider the following cost effective upgrades, in no particular order:
>
> (a) Use of Performance Additives;
> (b) Use of more Reactive Sorbent;
> (c) Increase the Pulverization Level of Sorbent;
> (d) Engineering redesign of atomizer or slurry injection system.

Industry has also recognized that the efficiency of existing SO_2 scrubbers can and have been upgraded significantly and a number of companies offer scrubber upgrade services. For instance, URS makes this statement in its, "Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants:"[33]

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[32] 70 FR 39171.
[33] Lipinski, George, et al, Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants, URS, April 5, 2011, p. A-5.

> Upgrades have been performed on a large number of FGD units over the past 15 years and have resulted in increased SO_2 removal performance to levels ranging from 92 – 99%. These have ranged from minor modifications to the internal components of a given unit, to enhance gas-liquid contact, to conversion of some units from one FGD technology to another coupled with the addition or modification of various balance-of-plant equipment or processes.

It is typically much more cost effective to upgrade an existing FGD than to install a completely new scrubber.[34] These existing scrubbers can be upgraded by applying new scrubbing technology[35] to improve their removal efficiency, lower operating costs, and improve operations and reliability for much less than it would cost to replace them with a new scrubber.

A scrubber can be upgraded by reusing as many structural components and equipment in the existing unit as possible, such as existing structural steel and absorber shells, ducts, pumps, and compressors. Scrubber upgrades have been completed on about 50 units in the last 15 years to enhance performance or lower overall operating costs.

As Staudt notes:[36]

> There have been numerous examples of FGD upgrades over the last several years that have improved SO_2 removal efficiencies. For example, the Fayette Station Unit 3, a 470 MW tangentially-fired coal unit in Texas, completed an upgrade to its 1988-vintage scrubber in 2010. The plant's control efficiency was increased from about 84 percent to 99 percent, higher than the guaranteed SO_2 removal efficiency of 95.5 percent. In Kentucky, E.On's Trimble County Generating Station Unit 1, a 550 MW tangentially-fired coal boiler, completed a scrubber upgrade in 2006. Its scrubber, installed in the 1980s, was originally designed for 90 percent removal efficiency. The scrubber system is now able to achieve over 99 percent SO_2 removal efficiency. In Indiana, NiSource upgraded the scrubbers at Schahfer Units 17 and 18 in 2009. The scrubber upgrades increased SO_2 removal efficiency from 91 percent to 97 percent.

Other successful scrubber upgrades include the AEP/SWEPCO Pirkey Unit 1 in Texas,[37] the San Miguel Electric Cooperative Unit 1 in Texas,[38] the Tuscon Electric Power Springerville Units 1

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[34] Maller et al, p. 5.

[35] See, e.g., Wolfgang Schuettenhelm and others, FGD Technology Developments in Europe and North America, Mega Symposium, 2001, http://www.babcockpower.com/pdf/rst-171.pdf.

[36] Staudt, James E., Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants Prepared For: Northeast States for Coordinated Air Use Management 89 South Street, Suite 602, Boston, MA 02111, March 31, 2011, p. 13.

[37] https://www.aeptexas.com/info/news/viewRelease.aspx?releaseID=146: "H. W. Pirkey Plant was equipped with an FGD system when it went into service in 1985. That system consistently removes nearly 80 percent of SO_2. This original equipment will be upgraded to bring its removal rate into the 90-percent range;" Tax Relief For Pollution Control Property Applications Filed for Harrison County 11/1994 & 10/2003. Available at: http://www.tceq.state.tx.us/assets/public/assistance/graphics/Prop2/harrison.pdf

[38] San Miguel Electric Cooperative FGD Upgrade Program Update, URS Corporation, June 30, 2014.

and 2 in Arizona;[39] the Gibbons Creek facility in Texas, the San Juan Generating Station in New Mexico;[40] the Culley Generating Station Units 2 and 3 in Indiana;[41] and the Trimble County Generating Station Unit 1 in Kentucky.[42] These upgrades have increased SO_2 removal to 92% to 99%.[43]

As we discussed in Section 5 in our wet scrubber retrofit cost calculations, a typical retrofitted scrubber is capable of 98% removal, down to an effective lower limit of 0.04 lbs/MMBtu. However, we recognize that scrubber upgrades are highly individualistic, depending on the particular equipment in use at the facility. Furthermore, we recognize that a number of the facilities we analyze for scrubber upgrades burn either PRB coals or blends of coals containing a large percentage of PRB coals. Consequently, in our analyses, we assign a presumptive scrubber upgrade target of 95% SO_2 removal, with the understanding that the ultimate individual efficiency will vary depending these factors.

6.1 Calculation of Existing Scrubber Efficiencies

In a typical situation in which we would propose that a pollution control device such as an SO_2 scrubber be installed, we would have historical emissions data to use as a baseline. In such an instance, we would apply the control efficiency of the scrubber to the uncontrolled historical SO_2 emissions, and be able to easily propose a controlled SO_2 emission rate that would be appropriate following the installation of the scrubber. However, we face a more difficult task in analyzing the efficiency of existing SO_2 scrubbers.

As we discussed above, we are confident that any of these existing scrubbers can be upgraded to perform similarly to newly retrofitted scrubbers. If we are to approach the task of calculating the cost of upgrading these scrubbers in a way similar to that of proposing a new scrubber, we must first be able to specify an SO_2 emission rate that would be appropriate following the installation of these scrubber upgrades. Because to our knowledge, none of these units monitors (via CEMS) their emissions before the exhaust gas traverses their existing scrubbers, we do not have CEMS

[39] Farber, et al, Results of FGD Upgrade Projects On Low-Rank Coals, Presented at Electric Power 2007 Conference and Exhibition EP-07 Session 12E2007. Covers upgrades to Pirkey Unit 1, San Miguel, and Springerville Units 1 and 2.

[40] Taylor, H., Nischt, W., San Juan Generating Station FGD Retrofit Project Update, Presented to: BR-1667 Power-Gen International '98, December 9-11, 1998, Orlando, Florida.

[41] Quitadamo, M., et al, SO_2 Removal Enhancement to the Vectren Culley Generating Station Units 2&3 Wet Flue Gas Desulfurization System, Babcock Power Technical Publication, Presented at the ICAC Forum 05', March 7-10, 2005, Baltimore, Maryland.

[42] Erickson, Clayton, et al, Wet Flue Gas Desulfurization (WFGD) Upgrade at the Trimble County Generating Station Unit 1, Presented at MEGA Symposium, August 28-31, 2006, Baltimore, Maryland.

[43] URS, 4/5/11, pp. A-5 to A-7; Babcock Power Environmental, Wet Flue Gas Desulfurization Scrubber Upgrades, 2009; Erickson, C., et al, Wet Flue Gas Desulfurization (WFGD) Upgrade at the Trimble County Generating Station Unit 1, Mega Sumposium 2006; Quitadamo, M. et al, SO_2 Removal Enhancement to the Vectren Culley Generating Station Units 2 & 3 Wet Flue Gas Desulfurization System, ICAC Forum 2005; Silva A., and Williams, P., WFGD Case Study – Maximizing SO_2 Removal by Retrofit with Dual Tray Technology, Mega Symposium, 2006; Henry S. Taylor and Walter Nischt, San Juan Generating Station FGD Retrofit Project Update, PowerGen; Maller G., et al, Improving the Performance of Older FGD Systems; B&W, Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, 2007 (8,000 MW of non-B&W wet FGD system upgrades by replacing the original absorber internals with tray technology and forced-oxidation conversions).

baseline SO_2 emissions. However, we do have coal quality data, which can be used to establish uncontrolled SO_2 emissions.

We calculated the scrubber removal efficiency by utilizing the reported sulfur content and tonnages of the fuels burned and reported to EIA,[44] and the monitored SO_2 scrubber outlet emissions reported to us.[45] We did this by constructing a spreadsheet[46], which among other things, divides the annual SO_2 emissions by the theoretical uncontrolled SO_2 emissions based on coal sulfur content to estimate the percentage of SO_2 in the coal that is emitted by each of the scrubbed facilities in Table 1. We calculated the theoretical uncontrolled SO_2 emissions from EIA reported coal sulfur data. This calculation is summarized below for a typical unit that burns both lignite and subbituminous coals:

$$(1)\ \left\{\frac{\left(\frac{\%\, S\, Lignite}{100}\, X\, tons\, lignite\, X \frac{2000 lbs}{ton}\right) + \left(\frac{\%\, SUB}{100}\, X\, tons\, SUB\, X \frac{2000 lbs}{ton}\right)}{\left(\frac{MMBtu}{ton\, lignite}\, X\, tons\, lignite + \frac{MMBtu}{ton\, SUB}\, X\, tons\, SUB\right)}\right\}\ X\ \left(\frac{2\, lbs\, SO2}{1\, lb\, S}\right)$$

$$= \frac{theoretical\ uncontrolled\ lbs\ SO2}{MMBtu}$$

or, alternatively expressed in tons:

$$(2)\ \frac{theoretical\ uncontrolled\ lbs\ SO2}{MMBtu}\ X\ \left(\frac{MMBtu}{ton\ lignite}\ X\ tons\ lignite + \frac{MMBtu}{ton\ SUB}\ X\ tons\ SUB\right)$$

$$= theoretical\ uncontrolled\ tons\ SO2$$

and the scrubber efficiency is then:

$$(3)\ Scrubber\ efficiency = 1 - \left(\frac{annual\ monitored\ tons\ SO2}{theoretical\ uncontrolled\ tons\ SO2}\right)$$

In equations (1) and (2), the percentage and tonnage values are those reported by the facility to the EIA for each fuel type. In equation (3), the annual EPA reported tons of SO_2 are those reported to us.[47]

In the following table, we summarize our calculation of the SO_2 removal efficiency for the existing scrubber systems:

[44] EIA Form 923. Available at http://www.eia.gov/electricity/data/eia923/
[45] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/
[46] See “Coal vs CEM data 2009-2013.xlsx,” tab “charts,” cell H12.
[47] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/

Table 14. Efficiency of Units with existing SO_2 scrubbers

Facility	**Unit**	**Scrubbed?**	**Bypass?**	**2009-2013 Average SO_2 Removal Efficiency (%)**
Sandow 4	1	Y	Y	75.7
Monticello	3	Y	Y	60.0
Martin Lake	1	Y	Y	69.2
Martin Lake	2	Y	Y	71.9
Martin Lake	3	Y	Y	69.8
Limestone	1	Y	Y	78.1
Limestone	2	Y	Y	77.0
San Miguel	1	Y	N	94.0
W. A. Parish	8	Y	Y	84.0

We were interested in gauging the accuracy and precision of our calculations of the theoretical uncontrolled SO_2 emissions, so we compared it to the EPA reported SO_2 emissions for units that do not have scrubbers. The following table presents that information:

Table 15. Comparison of theoretical to monitored SO_2 emissions for unscrubbed units

Unit	2009-2013 average monitored SO_2 emissions (tons)	2009-2013 average theoretical SO_2 emissions (tons)	Percentage theoretical to monitored SO_2 emissions (%)
Big Brown Unit 1	30,606.1	32,489.3	6.2
Big Brown Unit 2	30,638.8	32,048.5	4.6
Coleto Creek	16,665.1	18,771.5	12.6
Monticello Unit 1	16,434.9	18,288.8	11.3
Monticello Unit 2	15,458.0	17,805.3	15.2
Tolk Unit 171B	10,223.9	11,582.1	13.3
Tolk Unit 172B	10,889.4	11,395.4	4.6
W. A. Parish Unit 5	14,295.6	17,480.7	22.3
W. A. Parish Unit 6	15,376.5	17,404.9	13.2
W. A. Parish Unit 7	12,119.3	14,604.6	20.5
Welsh Unit 1	7,956.4	9,618.3	20.9
Welsh Unit 2	8,075.8	9,483.2	17.4
Welsh Unit 3	8,490.6	9,794.1	15.4
Average			13.6

This table shows that the actual SO_2 emissions as measured by CEMS are about 13.6% lower than the SO_2 estimated from coal quality data. The difference between these two numbers could be due to a number of factors, generally acknowledged in the literature, which include:

- Inadequate coal sampling including factors such as sample size, frequency, location (at the mine, train manifest, pile, blending hopper, silos, conveyor belts);
- Errors in reporting of the coal sulfur data, the heating value of the coals, and the amount of coal burned. We expect these errors to be compounded for units that blend coals.
- Our assumption that all coal sulfur will be oxidized to SO_2 in equation (1) at the theoretical rate of 2 pounds SO_2 for every pound of S. Some of the sulfur is in fact converted to other sulfur compounds such as SO_3 that are not measured by the SO_2 CEMS.[48]
- Potential effects of NOx and PM pollution control devices. SCRs, which are operating at the Parish units, convert a small amount of SO_2 to SO_3 as a consequence of the catalysts. Low SO_3 conversion SCR catalysts are available, but we do not know if the Parish units employ them. ESPs and baghouses reduce sulfur by removing particulate matter with absorbed SO3. Further, the filter cake in a baghouse absorbs SO_3.[49]
- Losses of sulfur, such as pyrite, when the coal is pulverized or in bottom ash.
- Sulfur reported on an as-received basis rather than dry basis; the as-received sample includes moisture, which would dilute (or lower) the sulfur content.

Therefore, we acknowledge that both our calculations of current SO_2 scrubber efficiency, and our calculations of tons of SO_2 removed once a scrubber upgrade is performed (and hence our cost effectiveness calculations) will have some error. We discuss how we propose to treat this in our Federal Register Notice for our proposed action.

6.2 Historical Scrubber Designs and Upgrades

The scrubber systems we are evaluating were all installed in the late 1970s to mid-1980s as part of the initial design of the facilities. All employ wet limestone, and with one exception – San Miguel – have scrubber bypasses. Scrubbers of this vintage were typically designed to meet the 1971 New Source Performance Standards (NSPS) for EGUs, which required new coal-fired boiler to meet a SO_2 limit of 1.2lb/MMBtu; or the 1979 NSPS, which additionally required 70% control, not to exceed 0.6 lbs/MMBtu unless 90% control was achieved. [50] Compliance usually involved using multiple absorbers with spares.[51]

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[48] Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Technical Update, EPRI, March 2012.

[49] R. Hardman, et al, Estimating Sulfuric Acid Aerosol Emissions from Coal-Fired Power Plants, U. S. Department of Energy-FETC Conference on Formation, Distribution, Impact, and Fate of Sulfur Trioxide in Utility Flue Gas Streams, March 1998; R. K., Srivastava, et al, Emission of Sulfur Trioxide from Coal-Fired Power Plants, J. Air Waste Manag Assoc. 2004 Jun;54(6):750-62.

[50] Flue Gas Desulfurization Inspection and Performance Evaluation Manual, EPA/625/ 1-85/019, October 1985, Sections 2.1.1.1 and 2.1.1; Farber, et al, p. 18.

[51] Spare scrubber modules allow FGD systems to maintain full or partial operating capability when a primary module fails or is down for service. Early scrubber design commonly included spares due to poor operating experience and the NSPS "emergency condition" provision. See, e.g., William DePriest and Rajendra P. Gaikwad, Economics of Lime and Limestone for Control of Sulfur Dioxide, 2003.

As Weilert notes,[52] “This is likely due to the requirement of the EPA’s new source performance standard (NSPS) for continuous compliance with a 30-day rolling average SO_2 removal, and the provision that stipulates a spare absorber module as a prerequisite to operation during emergency conditions with a malfunctioning FGD system.” However, industry gradually recognized that module spares were not required due to advances in scrubber technology, and the proven reliability of single-module FGD systems.[53] Thus, utilization of an existing spare FGD module at one of the facilities we are analyzing (Limestone) potentially represents a cost effective opportunity to increase scrubbing capacity. The following tables summarize the FGD information we have available as a result of mandatory reporting to the EIA via Forms 860 and 923, and from Weilert:[54]

[52] Carl Weilert, FGD Systems Utilizing Single Absorber Modules: The Wave of the Future for New Utility Boilers, Burns & McDonnell Technical Paper.

[53] Bailly Generating Station Advanced Flue Gas Desulfurization System, Final Environmental Information Volume, April 1989; Carl Weilert, Ibid., p. 12: “The available data indicates that single-module FGD systems can be extremely reliable.”; Frazer, C., et al, Fayette Power Project Unit 3 FGD Upgrade: Design and Performance for More Cost-Effective SO_2 Reduction, Babcox and Wilcox Technical Paper presented at the EPRI Mega Symposium 2010, p. 3: “Ultimately, the options selected, and discussed above, offer the station the flexibility to permanently remove one of the absorbers from regular service.” Taylor et al, Control of SO_2 emissions from power plants: A case of induced technological innovation in the U. S., Technological Forecasting & Social Change 72 (2005) 697 718. ….” Page 715: “ … according to a study of 111 FGD installations in 1986-1988 that declared that reliability was no longer an issue with FGD. With increased reliability, costly design options such as spare absorber modules were dropped in the 1990s.”; Schuettenhelm, W et al, FGD Technology Developments In Europe And North America, Babcock Technical Paper, Presented at the EPA-DOE-EPRI Mega Symposium Arlington Heights, Illinois, August 20-24, 2001, p. 3: “The F. B. Culley FGD (Vectren) system located near Evansville, Indiana … was designed to remove 95% of the SO_2 based on a 10 lb/MMBtu fuel. A unique feature of the project is that it uses one absorber to serve two generating units with no bypasses.”

[54] Weilert, C., and Meyer, E., Utility Design Trends, Power Engineering, 8-1-2010; personal communication.

Table 16. Summary of FGD information[55]

Facility	Units	2011 EIA 860								2012 EIA 923		
		In-service year	Sorbent Type 1	Sorbent Type 2	Bypass?	FGD Trains	FGD Trains at 100% Load	Design Removal Efficiency (%)	Flue Gas Entering FGD (%)	Efficiency at Annual Operating Factor	Tested Efficiency at 100% Load	Date Latest Efficiency Test
Sandow 4	1	1981	LS	DB	Y	3	3	92	83	74.4	74.4	01/1984
Monticello	3	1978	LS	DB	Y	3	3	95	75	55	55	01/2007
Martin Lake	1	1977	LS	DB	Y	4	4	95	95	64.7	64.7	02/1991
Martin Lake	2	1978	LS	DB	Y	4	4	95	95	64.9	64.9	02/1991
Martin Lake	3	1979	LS	DB	Y	4	4	95	95	67.8	67.8	02/1991
Limestone	1	1985	LS	DB	Y	5	4	90	100	77.1	91.5	12/2011
Limestone	2	1986	LS	DB	Y	5	4	90	100	75.8	91.5	12/2011
San Miguel	1	1982	LS		N	4	4	94.2	100	94.1	94.3	05/2010
W. A. Parish	8	1982	LS		Y	3	3	85	82	81.9	73	01/1985

[55] We question the accuracy of some of this information reported to EIA. For instance, the Limestone facility reports that it has a bypass for its scrubbers, yet it reports that 100% of the flue gas enters the scrubber. Also, the Martin Lake facility reports that for Unit 1, 95% of its flue gas enters its FGD and that of that gas, the removal efficiency is 95%. This would result in an overall SO_2 removal efficiency of 90.3% (0.95 X 0.95). However, our own calculations indicate an average removal efficiency of much less. We suspect the EIA scrubber efficiencies are a mixture of supplier guarantees (not counting bypassed flue gas) and actual estimates.

Table 17. Selected information from Weilert and Meyer

Facility Name[a]	FGD ID[b]	Process Type[a]	Absorber Type I[b]	Sorbent Type[b]	Provision for Bypass[b]	Incorporation of Spare Module[b]	Manufacturer[b]	Material of Construction	Oxidation Mode
Limestone	1	Wet Limestone	SP	LS	Y	Y	AL	NIe	Forced[e]
Limestone	2	Wet Limestone	SP	LS	Y	Y	AL	NIe	Forced[e]
Martin Lake	1	Wet Limestone	TR[m]	LS	Y	N	HRC	FRCS[f]	NR
Martin Lake	2	Wet Limestone	TR[m]	LS	Y	N	HRC	FRCS[f]	NR
Martin Lake	3	Wet Limestone	TR[m]	LS	Y	N	HRC	FRCS[f]	NR
Monticello	3	Wet Limestone	SP	LS	Y	N	MX	FRCS[f]	NR
San Miguel	1	Wet Limestone	TR[m]	LS	N	N	BW	SS[m]	Inhibited[e]
Sandow	4	Wet Limestone	SP	LS	Y	N	AL	SS[e]	NR
W A Parish	8	Wet Limestone[f]	SP	LS	N[56]	N	MX	FRCS[f]	NR

Notation from Weilert and Meyer

a This column is from the 2010 “Emissions” section of EPA’s Clean Air Markets Division “Data and Maps” website
b This column is from 2008 EIA-860 data Schedules 6-G & 6-H
c This column is from 2008 EIA-860 data "Annual Electric Generator Report" Generator (Existing) File
d 2009 “Emissions” section of EPA’s Clean Air Markets Division “Data and Maps” website
e Information is from respective vendor either from direct correspondence or from their website/publications
f DOE "Utility FGD Survey January - December 1989" Publication Number ORNL/M-2347
g 2008 “Emissions” section of EPA’s Clean Air Markets Division “Data and Maps” website
h 2007 “Emissions” section of EPA’s Clean Air Markets Division “Data and Maps” website
I 2008 EIA 860 data “Annual Electric Generator Report” Generator (Proposed) File
j Material information from Stebbins Manufacturing Installation List
k Upgrade by BPE according to BPE
l 2005 EIA 767 data Schedule 8 A & 8 B

[56] We note that the Weilert and Meyer data reports that the W A Parish facility does not have a scrubber bypass, yet the EIA data reports that the facility does have a bypass. Examination of aerial photos of Unit 8 seem to confirm the presence of ducting that would serve a bypass.

m Authors' correction based on personal knowledge
n Facility's Utility's website
o EPA's Steam Electric Power Generating Point Source Category: 2007/2008 Detailed Study Report (Online)
p Multiple FGD units are associated with one generator. The value reported is the nameplate capacity for the generator.

General	Absorber Type	Sorbent Type	Material of Construction	Unit Manufacturers
NA Not Applicable	BR Jet Bubbling Reactor	AF Alkaline fly ash	CO Combination	AD Allied
NR Not Reported	CD Circulating Dry Scrubber	LA Lime and alkaline fly ash	CS Carbon Steel	AL Alstom
	DCFS Double Contact Flow Scrubber	LF Limestone and alkaline fly ash	FRCS Flakeglass Reinforced Resin	AM American Air Filter
	DSI Dry Sorbent Injection	LI Lime	Lined Carbon Steel	AP Airpol
	PA Packed	LS Limestone	FRP Fiberglass Reinforced Plastic	AV Advatech
	SD Spray Dryer	MO Magnesium oxide	NI Nickel Alloy	BPE Babcock Power Environmental
	SP Spray	SA Soda ash	RLCS Rubber Lined Carbon Steel	BW Babcock and Wilcox
	TR Tray	SC Sodium carbonate	SS Stainless Steel	CH Chiyoda
	VE Venturi	SL Soda liquid	TL Tile Lined	FMC FMC
				HI Hitachi
				HRC Hamon Research Cottrell
				KE M W Kellogg
				MHI Mitsubishi Heavy Industries
				MX Marsulex
				SHU Saarberg Holter
				SI Siemens
				OT Other

The Instructions for EIA Form 860 indicate the following regarding the fields of interest to us:

Can flue gas bypass the flue gas desulfurization unit? Indicate whether the flue gas can bypass the FGD unit.

What is the total number of flue gas desulfurization unit scrubber trains or modules? Enter the total number of flue gas desulfurization unit scrubber trains or modules operated.

How many flue gas desulfurization unit scrubber trains or modules are operated at 100 percent load? Enter how many flue gas desulfurization unit scrubber trains or modules are operated at 100 percent load.

What is this unit's design removal efficiency for sulfur dioxide when operating at 100 percent load? Report the design removal efficiency to nearest 0.1 percent by weight of gases removed from the flue gas when operating at 100 percent generator load.

The instructions for EIA Form 923 indicate the following regarding the fields of interest to us:

FGD or FGP Efficiency Rate at Annual Operation Factor (H, K): Enter removal efficiency, based on the annual operating factor. Annual operating factor, as given by the formula below, is defined as the product of design firing rate and hours of operation per year, divided by annual total fuel consumption, expressed as a percentage. If actual data are unavailable, provide estimates, based on equipment design performance specifications.

> *Annual Operating Factor (AOF) =*
> *100 * Design Firing Rate (MMBtu/hr) * Hours of Operation (hr) / Total Fuel Consumption (MMBtu)*
> *Removal Efficiency at Annual Operating Factor = FGP Removal Efficiency * Average AOF*

FGD or FGP Tested Efficiency Rate (at 100% Load) (I, L): Enter the tested efficiency of the FGD and/or FGP unit for each controlled pollutant. If not tested at 100% load, provide the load at which the test was conducted in a comment on Schedule 9. If an efficiency test has not been conducted, leave field blank and provide a comment.

Test Date (J, M): Enter the date of the latest efficiency test for the FGD and/or FGP unit for each controlled pollutant. If no test was conducted, leave the test date blank.

These first generation FGD units were typified by multiple absorber modules, SO_2 removal efficiencies between 75% and 90%, and the use of either natural or inhibited oxidation.[57] However, as Staudt notes,[58] "… limestone-forced oxidation (LSFO) wet scrubber technology is [now] the most widely used form of wet FGD and is more widely used on coal-fired power plants than every other form of FGD combined. State-of-the-art LSFO systems are capable of providing very high levels of SO_2 removal – on the order of 98 percent or more." These early units were often designed to operate with a dry stack, which was most often accomplished by bypassing a portion of the flue gas around the scrubber to maintain gas temperatures high enough to prevent condensation and the formation of H_2SO_4 which would erode an unprotected chimney. These older scrubbers represent a significant investment that can be optimized, improved, and/or upgraded to minimize the cost of reducing SO_2 emissions.

These early scrubbers typically employed two scrubbing zones, a venturi section with spray nozzles to enhance gas-liquid mixing and a second spray zone. The second zone sometimes included a tray or packing to enhance gas-liquid contact.[59] They had many operational problems including poor reagent utilization, tray scale, ducting problems, and plugging of nozzles and demisters.[60] Solids deposited on these devices, plugging them, reducing flow and increasing differential pressure, requiring weekly cleanings and driving up O&M costs. The resulting high O&M costs led to replacement of packings and redesign.[61]

We know from our review of the facility's responses to our information collection requests, described in Section 7.1, that many, if not all of these original scrubbers have been modified since their original installations to cure these and other problems. However, there is very little publicly available documentation. A number of key factors have pushed owners to upgrade their scrubbers, often absent any regulatory drivers including: [62]

- Reduction in operating costs
- Reduction in maintenance costs
- Flexibility to burn higher sulfur coals
- Sale of byproduct (upgrade to forced oxidation allowing the sale of gypsum)
- Opportunity to generate excess emissions credits for sale,
- An increase in the SO_2 emission credits price 20
- Reduction in auxiliary power consumption

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[57] Farber, et al.
[58] Staudt, James E., Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants Prepared For: Northeast States for Coordinated Air Use Management 89 South Street, Suite 602, Boston, MA 02111, March 31, 2011. p. 10.
[59] Buecker, B., Important Concepts of Wet-Limestone Flue Gas Desulfurization Energy-Tech Magazine, October 2008, http://www.energy-tech.com/article.cfm?id=21789; PEl Associates, 1985.
[60] See, e.g., NERC, Impact of FGD Systems. Availability Losses Experienced by Flue Gas Desulfurization, July 1991, pp. 10, 27; Farber, et al, Ibid.
[61] Buecher, Brad. Ibid.
[62] Klingspor, J., Brown, G., Techniques for Improving FGD System Performance to Achieve Ultra-High SO_2 Removal Efficiencies, URS Technical Paper; Frazer, C., et al, Ibid., p. 8: "The unit also has the option to burn lower-cost, high-sulfur coal, while still maintaining emissions limits;" NERC, Impact of FGD Systems. Availability Losses Experienced by Flue Gas Desulfurization, July 1991; Maller, G., et al; Taylor, H., Nischt, W., p. 5: "This conversion project was justified on the basis of O&M and power/fuel savings."

- Solving process problems that cause high maintenance, reagent, and disposal costs
- Improving reliability (reducing scrubber-related outages)
- Ability to treat a higher volume of flue gas to improve scrubbing efficiency

Analyses of these upgrades reveals that they typically have performed better than guaranteed. Our examination of the facility's responses to our information collection requests, lead us to conclude that some of these existing scrubbers are able to operate at higher removal efficiencies than they currently achieve due to changes in the factors that led to their upgrades. For example, our regulations have been delayed through litigation, SO_2 allowance markets have not materialized or allowance costs have not risen as expected, changes in natural gas pricing, etc. Consequently, we suspect that absent a specific permit limit, other enforceable requirement, or market driver to operate at these higher scrubber efficiencies, some of these facilities may simply choose not to do so for economic reasons. For example, it has been suggested that some facilities owners turn off their scrubbers at peak demand to maximize profits.[63]

6.3 Options for Upgrading SO_2 Scrubbers

The performance of older FGDs is often limited by poor reliability and poor design, resulting in lower SO_2 removal efficiencies and higher operating and maintenance costs than newer FGD systems. The causes for poor performance include the following:[64]

- Bypassing a portion of the flow around the scrubbers
- Unbalanced flow between absorbers
- Poor gas distribution within the absorber
- Poor spray coverage within the absorber
- No droplet-to-droplet interaction within the absorber
- Sneakage along the sides of the absorber
- Poorly designed mist eliminator wash systems
- Inadequate scrubber chemistry

Existing FGD systems can be upgraded by applying new scrubbing technology[65] and improved upon in many instances so that they can operate at performance and reliability levels similar to new systems for much less than it would cost to replace them with a new scrubber.[66] As noted in the BART Rule, "upgrading an existing scrubber system is typically considered more cost

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[63] Wynne, H., et al, U.S. Utilities: Can Texas Comply with the Cross-State Air Pollution Rule? Yes, If Existing Scrubbers Are Turned On, Bernstein Research, July 20, 2011, p. 5: "This pattern suggests that generators have sought to avoid the reduction in net generation that results from operating the scrubbers (reflecting the parasitic load of the emissions control equipment) during hours when power prices are highest. Conversations with the investor relations departments of Energy Future Holdings and NRG Energy confirmed that, as long as continuous operation of SO_2 scrubbers is not required to comply with currently prevailing SO_2 emissions limits, generators will avoid operating the scrubbers so as to maximize net power output and revenues, and minimize variable operation and maintenance expense, including the cost of sorbents and water required for the operation of the SO_2 scrubbers."

[64] Klingspor, J., Experience from 52,280 MWs of Wet Flue Gas Desulphurisation System Upgrades, VGD PowerTech, December 2012.

[65] Schuettenhelm, W et al; Maller, G., et al; Klingspor, J.,et al; Farber, P., et al; Klingspor, J., et al.

[66] Maller, G., et al, p. 13.

effective than constructing a new scrubber system."[67] Dr. Jonas Klingspor, Vice President at URS, a firm that has conducted more than 52,000 MWs of scrubber upgrades, stated that, “a scrubber upgrade is typically about one-third or less than the cost of a new scrubber.” This is because a scrubber system can be upgraded by reusing many existing structural components and existing equipment, such as existing structural steel and absorber shells, ducting, pumps, and compressors. Other components can be modified or replaced with new technology. Also according to Klingspor:[68]

> Most wet FGD systems, regardless of initial physical design or chemistry, can be upgraded to achieve above 99% SO_2 removal efficiency and to operate uninterruptedly between scheduled outage cycles.

As described repeatedly in the scrubber upgrade references we provide, a scrubber system can be upgraded by reusing many existing structural components and existing equipment, such as existing structural steel and absorber shells, ducting, pumps, and compressors. There are many viable, cost-effective options to improve SO_2 removal efficiency. These include: [69]

- Removing any existing scrubber bypass;
- Eliminating sneakage of gases down the sides of the absorber bypassing the spray headers, by installing wall baffles or rings within the absorber;
- Improving liquid distribution by installing new spray headers, additional spray levels and/or more efficient nozzles to improve spray coverage in the absorber;
- Improving gas-liquid contact by adding trays within the absorber;
- Increasing the gas-to-liquid ratio by increasing recycle slurry pump flow by, for example, using all available scrubber modules, adding recirculation pump suction line screens or changing pump gear reducers to allow higher impeller speeds, thus producing greater slurry flow on pumps;
- Improving scrubber chemistry by reducing limestone grind size, eliminating limestone blinding, converting to inhibited or forced oxidation, optimizing pH, and using performance additives such as dibasic acid (DBA);
- Redesigning mist eliminators and mist eliminator wash system to handle higher velocities through the absorber;
- Repairing any damaged or worn parts, such as recycle pump impellors; and
- Removing any capacity constraints, such as in the dewatering system or induced draft fan.

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[67] 70 FR 39133.

[68] Klingspor, J., Experience from 52,280 MWs of Wet Flue Gas Desulphurisation System Upgrades, VGD PowerTech, December 2012.

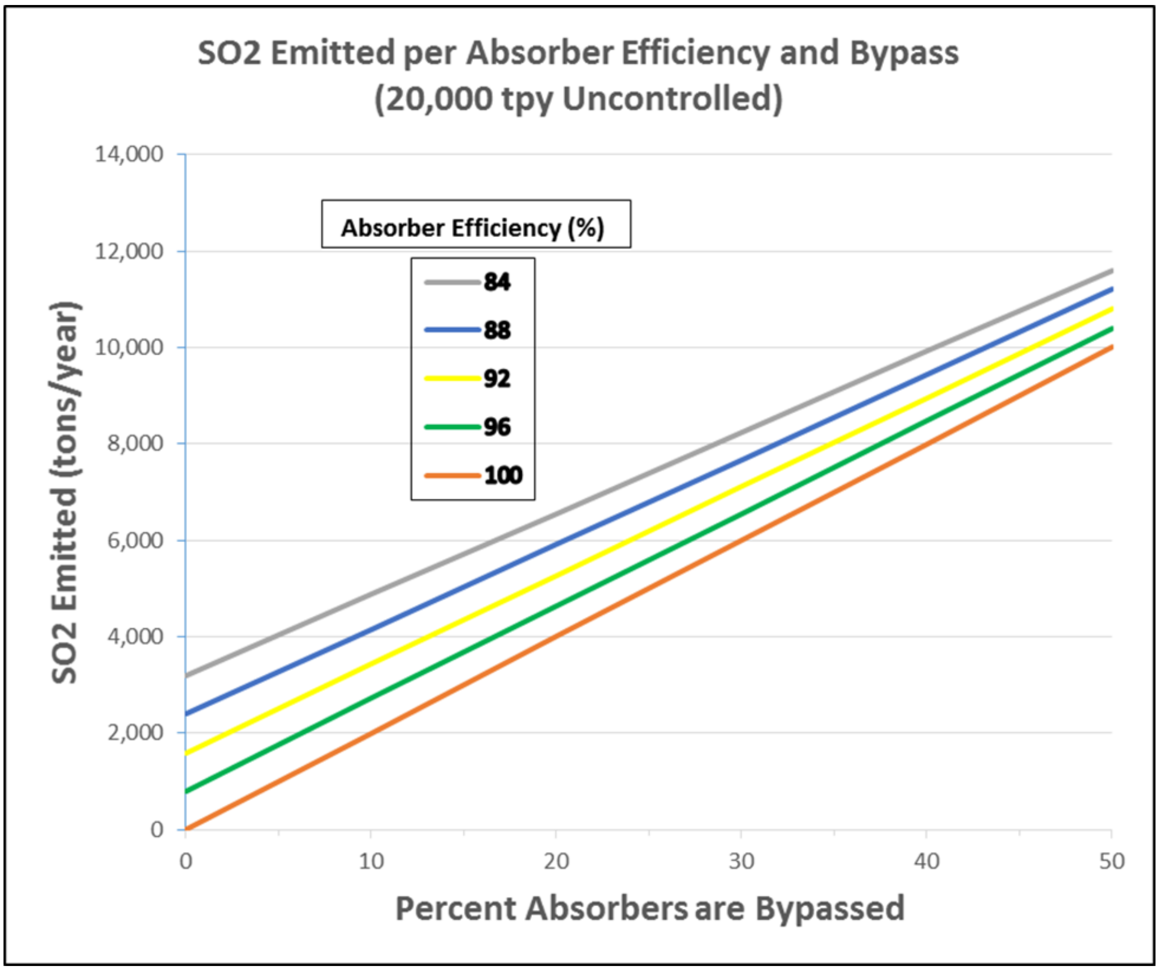
[69] See for example: Klingspor, J., p. 106; Maller, G., et al; Klingspor, J. and Brown, G; Alstom, Wet Scrubber Upgrade Air Quality Control Systems, http://www.alstom.com/Global/Power/Resources/Documents/Brochures/wet-scrubber-upgrade-datasheet.pdf;
Moretti, A., State-of-the-Art Upgrades to Existing Wet FGD Systems to Improve SO_2 Removal, Reduce Operating Costs and Improve Reliability, Power-Gen Europe, June 3-5, 2014.

We discuss these scrubber upgrade options in the sections that follow. These methods have been used on many vintage scrubbers in the last 20 years to enhance performance and/or to lower overall operating costs.[70]

6.3.1 Elimination of Scrubber Bypass

As we note above, a flue gas bypass is used on all of the scrubber systems we are investigating for upgrades, except for the San Miguel unit. A bypass allows the facility to route all or a portion of the flue gas around the FGD system for flue gas reheat and/or to improve operating flexibility. Some utilities originally designed the FGD system to scrub only a percentage of the flue gas while others installed bypass capability as a means of providing continuous operating capability, using alternate method for flue gas reheat. Because a bypass can route a large volume of flue gas around the scrubber system, it can have a significant impact on the overall SO_2 removal efficiency of the unit. Below is an example of this:

Figure 2. Effect of Bypass and Absorber Efficiency on SO_2 Emitted



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In the above example for a coal fired power plant that would emit 20,000 tons per year (tpy) if uncontrolled, the difference between no bypass and 20% bypass is significant. For example, if the absorbers are 96% efficient, a 20% bypass would mean that 3,840 tpy more is emitted over no bypass.

A wet FGD sprays a limestone-based slurry into the gas stream to remove SO_2. This produces a gas stream that is saturated with water vapor at a temperature of 136-145 F for lignite and sub-bituminous coal. A wet scrubber cools the stack gas and adds moisture to it. The gases are saturated and contain water droplets containing corrosive compounds such as sulfuric acid. If the temperature of the flue gas is blow the dew point, the moisture condenses in the exit ducts, stack walls, etc., corroding downstream equipment. Gasses emitted to the atmosphere can result in liquid fallout, visible steam plumes and plume touchdown, causing high ground-level SO_2 concentrations.[71] Thus, unless corrosive resistant materials are utilized, the temperature of the flue gases exiting the FGD system must be above the dew point to avoid condensation of flue gas and to maintain flue gas velocities in the exit ducts and stack.

At the time the subject scrubbers were installed, this was accomplished by heating the flue gas exiting the FGD system by about 25 to 50°F[72], so it was slightly above the saturation point. This increased the buoyancy of the plume, which reduced ground-level pollutant concentrations; reduced plume visibility by eliminating entrained moisture; and evaporated entrained water droplets, decreasing the potential for corrosion. Four methods were historically used to address this problem:[73]

- In-line reheat, in which the gas is passed through a heat exchanger located in the duct work (20%)
- Indirect hot air injection reheat (15%), in which air is heated in an external heat exchanger and then mixed with the exit flue gas
- Direct combustion reheat (14%), in which hot combustion gases are generated using fuel oil or natural gas and then mixed with the exit flue gas
- Bypassing a portion of the untreated flue gas around the scrubber and then mixing that hotter gas with the scrubbed flue gas (25%)

Bypassing flue gas was the lowest cost approach, followed by in-line reheat system.[74] This is the option used by all of the scrubber systems we are analyzing, with the exception of San Miguel, which does not employ a bypass. This was most commonly accomplished by routing 5%-20% of the flue gas around the scrubbers.[75] A bypass allows the facility to route all or a portion of the flue gas around the FGD system for flue gas reheat and/or to improve operating flexibility. Some utilities originally designed the FGD system to scrub only a percentage of the flue gas

[71] Henzel, D., et al, Limestone FGD Scrubbers: Users Handbook, EPA-600/8-81-017, August 1981, p. 2-27.
[72] Froelich, D., Graves, G., Eliminating Reheat from Existing FGD Systems, A Design and Economic Evaluation, Journal of the Air Pollution Control Association, v. 3 7, no. 3, March 1987, pp. 314 - 321, p. 314
[73] Froelich, D., Graves, G, p. 315. Note percentages refer to FGD systems that used any type of stack gas reheat. Some FGD systems did not employ any stack gas reheat.
[74] Henzel, D., et al, p. 2-28.
[75] Klingspor, J., Brown, G., p. 8; Maller, G, p. 4.

while others installed bypass capability as a means of providing continuous operating capability, using alternate methods for flue gas reheat.

Many of these early scrubber systems had/have variable bypass capability, including Monticello Unit 3; Martin Lakes 1, 2, and 3; and Sandow 4.[76] Variable bypass is used to adjust for different operating conditions, such as to maintain minimum stack temperature, adjust for variations in coal sulfur levels, and/or to maintain compliance with permits. Variable bypass was accomplished by adjusting the position of louver-type dampers on each scrubber tower, based on measurements of stack temperature, bypass fan parameters, and bypass damper position indicators.

Partially bypassing the scrubber reduces the overall scrubbing efficiency, as not all of the flue gases are treated. Consequently, one way to improve SO_2 removal efficiency is to eliminate the bypass and route 100% of the gases through the scrubber. When the bypass/reheat is eliminated, the amount of gas to be treated increases, the gas velocity decreases, and the gas density increases, resulting in system pressure losses of 5% to 10%, compared to dry operation.[77] This requires that two technical issues be addressed.[78]

First, the scrubber must have adequate capacity to handle the increased gas volume and be able to operate at higher flue gas velocities, which can cause problems with existing equipment such as the mist eliminators and stack. Scrubber capacity is generally not an issue if a scrubber system was designed with a spare absorber or spray level, which was common with many early scrubbers due to uncertainty about performance. This is probably not an issue for one of the subject Texas facilities (Limestone) as it was designed with multiple units plus a spare, which likely provides adequate capacity to handle bypassed gases. Absent a suitable spare, the existing scrubber may have to be modified to accommodate the higher flow, including replacement of the mist eliminators.

Second, existing stacks on currently scrubbed units are designed for hot dry flue gases with a higher gas velocity (~100 ft/sec) in the liner than new wet stacks. The stack downstream of a wet scrubber without bypass or reheat is a "wet stack", which exhausts saturated, scrubbed flue gas that contains droplets from mist-eliminator carryover. Thus, a new or modified mist eliminator and stack are usually required to accommodate the highly corrosive, saturated flue gas. The wet stacks must be designed using corrosion-resistant material and a gas velocity of 55 to 75 ft/sec to prevent condensed moisture from being carried out the top of the stack.[79] As mentioned above, when the bypass is eliminated, corrosive moisture condenses on downstream equipment that was not originally designed for these conditions, including scrubber outlet, ducts, bypass dampers, expansion joints, and the stack.

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[76] Supplied June 17, 2014 by Luminant, in response to request for information under Section 114(a) of the CAA, dated May 20, 2014.6/17/14.

[77] Revised Wet Stack Design Guide, Electric Power Research Institute (EPRI), 2012 Technical Report, Final Report, December 2012, p. 3-2.

[78] Maller, G., et al, p. 4.

[79] DePriest, W., Gaikwad, R., Economics of Lime and Limestone for Control of Sulfur Dioxide, p. 9; Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent and Lundy, p. 25; EPRI 2012, Table 2-1. Froelich, D., Graves. G., p. 317.

The cost of converting from dry to wet stack operation depends upon the existing materials used in these components. Moisture condensation within a stack designed for dry use can cause severe damage, as these stacks are typically lined with carbon steel or grouted brick. Considering the latter, moisture migration through the grout would corrode metal liner bands, weakening the stack and eventually resulting in stack failure. An acid-resistant brick liner may require no changes at all, while a carbon steel liner would require an alloy lining or other protection. Only the stack drainage system would likely have to be improved for acid brick lined stacks.[80]

The conversion of a dry stack to wet operation must address several issues that were not present when a bypass or reheat was used. Some of these issues include:[81]

- Stack liquid discharge;
- Plume downwash and icing;
- Corrosion/chemical attack;
- Stack height;
- Stack-liner geometry and material of construction;
- Liner-breach geometry;
- Stack liner geometry and material of construction;
- Gas velocity in the liner; and
- Liquid-collection devices and drainage.

A critical design consideration in converting a dry stack to wet operation is whether the existing liner and ductwork material can withstand the reduced temperatures and wet conditions of wet operation and whether the liner-gas velocity will result in droplet re-entrainment from the stack wall.[82] These issues may be addressed by modifying the existing stack or replacing it with a new "wet" stack. Mist eliminators, designed to reduce liquid carryover and slurry to downstream ductwork and the stack, must often be modified when the bypass is eliminated to facilitate wet stack operation.[83] These issues are further discussed in Section 7 concerning the costs of scrubber upgrades.

Relining a stack has become a common upgrade to power plants. As a general indicator of the scale of stack lining projects, Johnson[84] reports that 126 stack liner projects using Fiberglass Reinforced Plastic (FRP) kicked off in the 2004-2008, inclusive timeframe. This includes a number of facilities in Texas: Fayette Units 1 and 2, J.K. Spruce Unit 2, Sandow Unit 5, and Oak Grove Units 1 and 2. FRP competes with various steel alloys as a stack lining material and thus represents only a portion of the total stack lining projects.

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[80] Maller, G., p. 4; See for example, http://www.hadek.com/project-reports/san-juan-power-station
[81] EPRI, 2012. Ibid., p. 1-2.
[82] EPRI 2012, p.. 1-3.
[83] EPRI, Sec. 2.3.1.
[84] Johnson, T., et al, The Rapid Growth of Fiberglass Reinforced Plastic (FRP) in FGD Systems, 2011, Table 3.

As an alternative to relining an existing dry stack for conversion to wet operation, operators can choose to build a new stack. However, this the most costly of these options.

6.3.2 Optimization of Liquid/Gas Ratio

The liquid-to-gas ratio (L/G ratio) is a sizing criterion for absorbers that compares the slurry recirculation rate to the flue gas flow rate. It is the ratio of the amount of limestone slurry expressed in gallons per minute to the amount of untreated flue gas in thousands (1000s) of actual standard cubic feet per minute (gpm/1000 acfm).[85] Increasing the L/G increases the alkalinity available per pass, which increases the SO_2 removal efficiency. The amount of flue gas is fixed by the boiler, so the L/G ratio is increased by increasing the amount of limestone slurry. This is typically varied by changing the number of operating recycle pumps.

In a conventional scrubber, the amount of slurry is increased by replacing an existing pump with a larger model, increasing the number of slurry recycle pumps and spray headers, upgrading the motors in existing recycle pumps, installing new gear reducers to allow the pumps to operate at higher impeller speed, or reducing the pump head by, for example, replacing high-pressure nozzles with low pressure nozzles.[86]

Sargent & Lundy notes[87] in a wet FGD evaluation that included 2.0 and 4.72 lb/MMBtu SO_2 coals, that most of the scrubbers installed in Phase 1 of the CAA title IV program (1995) were designed for and achieved 95% efficiency with L/Gs of 90-130 and inlet sulfur dioxide up to 8 lb/MMBtu. Demonstrations and testing by the major FGD process developers, including Alstom, Mitsubishi, Babcock & Wilcox, and Wheelabrator, have shown that a 130 L/G is adequate to achieve 98% efficiency in a typical open-spray tower design on the 4.72 lb/MMBtu inlet SO_2 basis (high-sulfur coal case) of this work. This is further verified by recent guarantees offered by FGD vendors for new unit applications.

6.3.3 Gas-Liquid Contact Improvements

SO_2 removal in a wet scrubber is controlled by the amount of SO_2 that can be absorbed per unit volume of recirculated slurry. SO_2 absorption is limited by the amount of solid and liquid phase alkalinity provided in each gallon of slurry. The absorption is also a function of the contact time between slurry and SO_2 as well as the absorber design, which determines the gas-slurry contact area. In a spray tower, the most common type of scrubber, flue gas typically enters horizontally and turns 90 degrees into a vertical open cylindrical vessel with multiple levels of spray headers. The flue gas is first cooled and saturated with slurry. The saturated flue gas then flows upward through the absorber spray zone, where slurry is sprayed countercurrent to the flue gas.

[85] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent & Lundy.
[86] Klingspor, J., Brown, G.
[87] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent and Lundy, p. 10.

The scale models used to design early scrubbers largely ignored the interaction of flue gas and slurry. The impact of spray nozzles on flue gas distribution was poorly understood and often ignored. Thus, the effect of nozzle spray angle; spray coverage as a function of nozzle size, type, density and pressure; and the impact of wall sneakage were typically not modeled.[88]

Thus, maldistribution of flue gas across the cross section of the absorber is a common cause of poor performance in vintage scrubbers. This is caused by high velocity flue gas entering the absorber, which causes it to hug the walls of the absorber, bypassing the spray headers. This effect is commonly known as "gas sneakage" and can be minimized or eliminated through the installation of various mechanical devices.[89] Gas sneakage also occurs around nozzles inside the absorber.

The skewed flow distribution in the absorber inlet often generates flue gas recirculation zones that cause buildup of solids. Similarly, a skewed flue gas distribution at the absorber outlet duct often leads to excess mist eliminator carryover, scaling of the absorber outlet duct, and stack rain issues.[90] These factors place a limitation on the maximum removal efficiency that can be achieved for a given absorber.

Poor recycle spray header design was another common problem in older FGD systems. The early designs used narrow-angle nozzles and a low nozzle density.[91] This resulted in non-uniform and incomplete spray coverage. Spray towers use several levels of spray nozzles that scrub the flue gas as it moves upward through the absorption tray and spray zone. However, these spray levels are usually not sufficient by themselves to adequately distribute flue gas at the base of the spray zone.[92] There are often significant holes in the spray coverage over the cross-sectional area of the absorber due to a tendency in early scrubbers to use a small number of relatively large spray nozzles. This problem is especially significant along the walls of the absorber as gas flows tend to be higher there, or in the vicinity of internal support members. This results in poor gas-liquid contact because the gas tends to flow where the spray density and gas-side pressure drop are the lowest, contributing to gas sneakage.

Incomplete spray coverage and gas sneakage can be eliminated by improving gas/liquid contact and thus the SO_2 removal efficiency with the goal of achieving a uniform distribution of slurry and gases across the scrubber diameter. Thus, upgrades typically must address uneven flow distribution issues, poor gas-liquid contact, and poor mixing in the reaction tank. This can be achieved by improving flow distribution using turning vanes, perforated plates, and wall rings; improving gas liquid contact using devices such as sieve trays, improved spray nozzle layout, and double hollow cone nozzles; and chemistry modification, including performance additives and conversion to forced oxidation. The specific option depends upon a range of factors such as

[88] Klingspor, J., p. 101.
[89] Klingspor, J., Brown, G.; Maller, G., et al.
[90] Klingspor, J., p. 102.
[91] Klingspor, J. 2012, p. 102 and Figures 2 and 3.
[92] See, for example, Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, Babcox and Wilcox, 2007, p. 6.

availability of space for a tray or packing and availability of fan power to overcome additional pressure drop.[93]

Wall Baffles

Wall baffles or liquid distribution rings are widely used to prevent gas sneakage down the sides of the absorber vessels. They are sloped downwards to re-inject wall slurry into the interior of the absorber where there is a greater chance of interaction with recycle spray droplets. They also promote more thorough mixing of flue gas, ensuring no areas of high SO_2 concentration. These baffles are placed between spray levels. Wall baffles have been used in many scrubber upgrades, including both round and rectangular absorber towers as well as large and small towers. [94] These rings result in improved performance with no increase in power consumption or pressure drop.[95]

Trays

Perforated trays or counter flow trays can be used to improve the gas-liquid contact and distribution of flue gas across the tower. The gases rise through the absorber, contacting a froth of slurry on the tray. This provides increased SO_2 removal by creating additional surface area obtained from liquid holdup on the tray. Trays uniformly distribute gas and create a bubbling zone that improves gas-liquid contact, yielding high SO_2 removals at a lower overall L/G. Adequate space and improved structural support are required to add a tray to an existing open spray scrubber or an additional tray to an existing tray scrubber.[96]

A tray is a much more efficient contact device than a slurry spray.[97] This is because the tray creates more surface area between the slurry and the gas. The limestone dissolution on the tray can be as much as 50% of the dissolution in the entire absorber. The improvement in SO_2 removal by adding a tray is very similar to adding liquid distribution rings or an additional spray level. A tray provides about the same removal efficiency as one spray header without requiring any of the cost and complexity of a recycle pump and spray header system.[98] The benefits of the absorber tray compared to an additional spray level include:

- Reduced liquid to gas ratios
- Increased absorption for the same L/G
- More uniform gas distribution due to back-pressure from tray
- Fewer recirculating pumps

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[93] Klingspor, J., 2012; Klingspor, J., Brown, G.; Maller, G., et al; Moretti, A., State-of-the-Art Upgrades to Existing Wet FGD Systems to Improve SO_2 Removal, Reduce Operating Costs and Improve Reliability, Power-Gen Europe, June 3-5, 2014.
[94] Maller, G., et al, Table 1 and pp. 4-5.
[95] Klingspor, J., Brown, G.
[96] Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, Babcox and Wilcox, 2007.
Silva, A., et al, WFGD Case Study - Maximizing SO_2 Removal by Retrofit with Dual Tray Technology, Presented to: EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium, August 28-31, 2006.
[97] Steam Its Generation and Use, The Babcox & Wilcox Company, Edition 41, 2005, p. 35-6.
[98] Klingspor 2012, p. 104.

- Fewer spray headers
- Reduced pump maintenance
- Increased particulate removal
- Corrects gas distribution problems in the lower part of the absorber spray zone
- Protects the inlet duct from scaling
- Provides the lowest cost approach to a FGD upgrade
- Provides a maintenance platform that avoids draining the reaction tank to gain access to the spray headers and mist eliminators.[99]

A tray will significantly increase the gas-side pressure drop and thus requires adequate fan capacity. The exact amount is a function of design and operating conditions, but is typically on the order of 1.5 to 2.5 in-wc.[100] However, the additional fan power required from the increased gas-side system pressure drop due to the tray is typically offset by a reduction in pumping power from the lower L/G (i.e., less slurry recycled) required to achieve a given SO_2 removal.[101] The savings in recycle pump power will offset the penalty of increased absorber pressure drop (i.e., pump versus fan power).[102] For moderate SO_2 removal improvements, a tray can allow the use of one less spray level and spray pump per absorber, reducing operating and maintenance costs.[103]

Trays are subject to plugging and scaling if scrubber chemistry is not controlled carefully, and trays are less attractive if absorber gas velocity is increased. However, they are desirable if space is limited, when efficient spray header designs are not present, and to correct skewed gas distribution profiles.[104] More than one tray can be employed to optimize the gas-slurry contact. Babcock and Wilcox, for example, report that scrubber efficiency can be improved by adding a second tray.[105] Adding a second tray increases contact time between SO_2 and slurry, which increases SO_2 removal efficiency.[106]

Spray Headers

The recycle spray header design of many older scrubbers results in incomplete spray coverage, especially near the walls where gas flows tend to be higher. These older designs have gaps or openings in the spray pattern that allow flue gas to bypass the spray zone without contacting the slurry. Many of these gaps are on the outside of the absorber, near the absorber walls and provide a direct path for the flue gas to bypass the slurry spray.[107] This results in poor gas-liquid contact which limits maximum removal efficiency.

[99] Klingspor 2012, p. 104.
[100] Maller, G., et al, Improving the Performance and Reliability of Older FGD Systems, Mega Symposium, August 2010.
[101] Moretti, A., 2014, p. 4.
[102] Staehle, R., Upgrading Your Wet FGD System, Marsulex, October 2008.
[103] Moretti, A., p. 4.
[104] Maller, G., et al, p. 3.
[105] Silva, A., et al.
[106] Moretti, A., p. 5.
[107] Moretti, A., p. 4, Fig. 4.

The spray headers can be replaced with a high-efficiency spray header that uses a high nozzle density and wide-angle nozzles. The older spray header designs also used a support system that was prone to breakage, resulting in header section failing and falling to the bottom of the absorber. Replacing the headers with a modern, self-supporting design reduces maintenance costs and outage time.[108] A high efficiency spray header in combination with double hollow cone nozzles can substantially improve performance, on average proving about a 40% increase in performance.[109]

Many state-of-the-art nozzle designs are available to upgrade scrubber performance. Bi-directional nozzles can be installed regardless of the original design, which provide wider-angle spray cones to provide complete coverage of the spray zone and increased gas-liquid contact. Side-by-side double hollow cone spray nozzles can be used to improve droplet interaction (secondary atomization), thus enhancing removal performance.[110]

These types of changes ensure a high degree of gas-liquid contact with reduced chance for gas sneakage and can significantly improve SO_2 removal efficiency and reduce O&M costs. New spray headers and/or new nozzles have been used in many scrubber upgrades,[111] including Fayette Unit 3.

6.3.4 Improving FGD Chemistry

SO_2 removal can be increased by improving slurry reactivity. There are many ways to do this, including reducing limestone grind size, eliminating limestone blinding, converting to forced oxidation, optimizing operating pH and using performance additives, discussed elsewhere. The easiest way to increase SO_2 removal efficiency in any scrubber is to increase the slurry pH. The SO_2 removal typically responds very quickly to an increase in pH. An increase in slurry pH is typically achieved by increasing the reagent feed rate, which causes limestone utilization to deteriorate. This deterioration can be offset by decreasing grind size, which allows operation at a higher pH while maintaining limestone utilization.[112]

Existing units that use natural or inhibited oxidation can be converted to forced oxidation. This process converts calcium sulfite to calcium sulfate and improves scrubber operating while providing a marketable gypsum byproduct.[113]

Limestone reagent fineness has a significant effect on limestone utilization, which in turn has a significant effect on FGD SO_2 removal efficiency. The finer the grind, the higher the removal efficiency as the fineness of the limestone affects the rate at which it dissolves in the reaction

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[108] Moretti, A., p. 5.
[109] Klingspor, J., 2012, p. 103.
[110] URS, Upgrade of Wet FGD Systems, Available at: http://urs-processtechnologies.com/wp-content/uploads/2013/02/FGD-Upgrade-Final-2_2013.pdf.
[111] See for example, Maller, G., et al, p. 3.
[112] Klingspor, J., Brown, G.
[113] Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, Babcox and Wilcox, 2007, p. 4.

tank.[114] The general rule of thumb today is 95% passing a 325-mesh screen.[115] Increasing the percentage that passes a 325-mesh screen increases the rate of limestone dissolution, which increases the removal efficiency. The majority of the subject FGD systems, those built before about 1995, were designed to produce limestone coarser than this optimum.[116]

Limestone reactivity is also important to scrubber operation. The chemical makeup of the limestone exerts a large influence on scrubber efficiency. In general, limestone with 94% or more calcium carbonate are very reactive, if properly ground. However, limestone with more than about 10% dolomite ($MgCO_3 \cdot CaCO_3$) are not desirable as the dolomite is rather non-reactive and tends to pass through the FGD untouched and thus does not participate in the chemical reactions that remove SO_2.[117]

6.3.5 Use of Organic Acids to Improve Performance

The use of organic acid additives, such as dibasic acid (DBA) and adipic acid, improves SO_2 removal efficiency by reducing the L/G ratio. Additional benefits of organic acids like DBA (beyond enhanced SO_2 removal efficiency) include reduced power consumption, lower spray pump flow, lower pressure drop, reduced limestone consumption, reduced overall operating costs, and reduced capital costs. They are also used as a backup, to allow a scrubber to be designed without a spare spray header and pump, and to allow increases in coal sulfur content.

The least expensive additives are organic acids that buffer the slurry liquor by acting as an acid or base to help dissolve limestone or to directly neutralize the sulfurous acid formed by the absorption of SO2.[118] Dibasic acid (DBA) is the most economical acid. It is a mixture of succinic, glutaric and adipic acids and is a byproduct in the manufacture of nylon. They can be used continuously or to maintain high SO_2 removal efficiencies if a recycle pump is taken out of service. They work by buffering the pH at the gas-liquid interface, thus reducing back pressure of SO_2 and by lowering the liquid-film resistance to mass transfer. DBA and formate are the most commonly used additives due to cost.[119]

The incorporation of organic acids into an upgrade can significantly reduce the capital, operating, and maintenance cost of the scrubber. This occurs because organic acids increase limestone absorption and stabilize the pH, reducing the liquid-to-gas ratio while maintaining the required SO_2 removal efficiency or increasing the removal efficiency for a given liquid-to-gas ratio. DBA has been reported to provide the equivalent of spraying an extra 20 gpm/1000 cfm of

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[114] Maller, G., Wet FGD Chemistry and Performance Factors, Presented at 2008 Power Gen Conference, December 1, 2008, pdf 48.

[115] LG&E Services Company Contract No. 501654, Mill Creek FGD Performance Upgrade Study, Babcock Power Environmental, February 2011, p. 53.

[116] Seward, R., Brame, K., A Review of Methods for Increasing Limestone Reagent Fineness for Flue Gas Desulfurization, Proceedings Tenths Symposium on Flue Gas Desulfurization, Vol. 1, February 1987.

[117] Buecker, B., Important Concepts of Wet-Limestone Flue Gas Desulfurization Energy-Tech Magazine, October 2008, http://www.energy-tech.com/article.cfm?id=21789; PEl Associates, 1985.

[118] Moretti, A., p. 5.

[119] Klingspor, J., and Brown, G.

limestone slurry. Thus, increasing SO2 removal from 92% to 95% can either add 25% to the pump energy input or buy an organic chemical.[120]

Their benefit over ultra-fine grind limestone is that the effect is immediate. There is no turnover of a slurry tank prior to the organic acid impacting absorber performance. However, their disadvantages include additional operating cost, uncertainty in long-term supply and pricing of DBA byproducts, possible contamination of gypsum by-product, and increased wastewater treatment cost.[121]

The U.S. Department of Energy and the Electric Power Research Institute conducted full-scale testing, process modeling, and economic evaluations of six utility flue gas desulfurization systems to evaluate low capital cost upgrades for achieving up to 98% SO_2 removal efficiency in existing FGD systems. These studies mostly involved using performance additives in the FGD systems, but other low cost options were evaluated using an EPRI model. The tested units are: Big Bend,[122] Merom,[123] Pirkey,[124] Gibson,[125] Elrama, and Kintigh.[126] These tests demonstrated the efficacy of organic acid additives. Many facilities add acid injection systems based on these and other test results, including (can we list the Texas units that use them?)

The addition of an organic acid system to an existing scrubber (that was not designed taking it into consideration) would increase the costs by a very small amount compared to the rest of a scrubber system. For instance, Invista reports the following based on modeling a 566 MW boiler using eastern bituminous high-sulfur coal (3% sulfur, 12,720 BTU/lb heating value) and 90% SO_2-removal efficiency:[127]

> Modeling shows that operational and maintenance costs of a wet limestone scrubber can be reduced by about 2% (about $200,000/year) when using DBA, including the cost of the DBA additive. The increased SO_2 scrubbing efficiency using DBA translates into about a 15% reduction in limestone use, a 1% reduction in steam, a 1% reduction in solid waste disposal costs, and a reduction of about 17% in power usage. Payback time, based on SO_2 credit prices of $200/ton, for the capital required to retrofit an existing wet limestone scrubber for DBA addition (storage tank, pump, piping) ranges from 5 months to about two years,

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[120] Invista DBA Will be Available to Improve FGD Efficiency, FGD & DeNOx Newsletter, No. 393, January 2011.
[121] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent and Lundy. p. 5.
[122] Radian Corp., Results of High Velocity Tests at Tampa Electric Company's Big Bend 4 FGD System, Topical Report, October 15, 1997.
[123] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, Evaluation of High Efficiency Test Results at Hoosier Energy's Merom Station, April 22, 1996.
[124] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, Results of DBA and Sodium Formate Additive Tests at Southwestern Electric Power Company's Pirkey Station, May 30, 1996.
[125] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, PSI Energy' s Gibson Station High SO_2 Removal Efficiency Test Program, May 20, 1996.
[126] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, Results of Sodium Formate Additive Tests at New York State Electric & Gas Corporation's Kintigh Station, February 14, 1997.
[127] The Role of Dibasic Acid (DBA) in Wet Limestone Flue Gas Desulfurization. Accessed from http://intermediates.invista.com/e-trolley/page_1035/, 7/7/2014.

depending on operating strategy (i.e. maintain SO_2 efficiency and reduce operating costs vs. improve SO_2 efficiency and profit from emission credits).

Consequently, the wastewater treatment system is the only item that might increase in capital and operating costs because organic acids increase the Basic Oxygen Demand (BOD) and Chemical Oxygen Demand (COD) of the wastewater, requiring biological treatment.[128] Wastewater treatment is typically a small fraction of the total cost of a scrubber.

6.3.6 Related Capital Improvements

The improvements discussed above generally require modifications to other facility components including the following:

- A new or modified stack
- A new or modified absorber if the original FGD did not include a spare
- A new or modified limestone slurry preparation system
- A new or modified dewatering system
- Upgraded flue gas system

When SO_2 removal is increased, the amount of wet FGD byproducts will increase. If the upgraded FGD system uses natural oxidation, the disposal pond may reach capacity. This usually requires conversion to forced oxidation to eliminate need for disposal ponds

If limestone consumption is increased to improve SO_2 removal, reagent preparation and dewatering systems may be undersized. In most cases, higher SO_2 removal requires finer grind than delivered by older system. Thus, existing milling systems may have to be upgraded to handle the new quantity and grinding requirements.[129]

Older FGD systems used thickeners for primary dewatering and rotary drum filters for secondary dewatering. Thickeners are prone to maintenance problems. These thickeners are difficult to operate when an FGD is converted to forced oxidation due to rapid settling of gypsum, requiring replacement with hydroclones, which are used in modern FGD systems.[130]

Older FGD systems used thickeners for primary dewatering and rotary drum filters for secondary dewatering. Thickeners are prone to maintenance problems. These thickeners are difficult to operate when an FGD is converted to forced oxidation due to rapid settling of gypsum, requiring replacement with hydroclones, which are used in modern FGD systems. The rotary drum filters

[128] Riffe, M., et al, Wastewater Treatment for FGD Purge Streams, Paper # 33, Presented at the MEGA Symposium 2008 Baltimore, MD, August 25 – 28, 2008; INVISTA DBA Dibasic Acid For Flue Gas Desulfurization November 17, 2010.
[129] Harper, G., Hagan, M.A., Dyer, P., and Breuer, W. J., Increasing Capacity of Existing Limestone Grinding Systems While Reducing Grind Size, Burns & McDonnell Technical Paper, 2006.
[130] Moretti, A., p. 8.

also may not have adequate capacity to handle increased SO_2 removal. The capacity constraint can be addressed by increasing the amount of time per day that the rotary drum filter operates; replacing the rotary drum filter with new generation rotary drum technology; or replacing them with vacuum belt filters.[131]

7 Scrubber Upgrade Analyses

We have conducted a cost analysis for upgrading the scrubbers for those facilities listed in Table 1 that currently employ a scrubber. As we discussed above in Section 6.1, we have calculated the SO_2 removal efficiency of these scrubbers as follows:

Table 18. Existing Scrubber SO_2 Removal Efficiencies

Facility	Unit	Bypass?	2009-2013 Average SO_2 Removal Efficiency (%)
Sandow 4	1	Y	75.7
Monticello	3	Y	60.0
Martin Lake	1	Y	69.2
Martin Lake	2	Y	71.9
Martin Lake	3	Y	69.8
Limestone	1	Y	78.1
Limestone	2	Y	77.0
San Miguel	1	N	94.0
W. A. Parish	8	Y	84.0

7.1 Section 114(a) Information Requests

In order to assess the potential range of options available to upgrade the scrubbers in the facilities listed above, we must have an understanding of what upgrades may have already been performed. Most of this information is not available publically. Therefore, for each one of these units, except for San Miguel, we have requested information under authority granted to us under Section 114(a) of the Clean Air Act, which included the following:

a. State whether any of the scrubbers have a bypass.

b. If a unit's scrubber has a bypass, describe whether the percentage of flow going to the scrubber is varied in practice by directly adjusting the bypass or if the bypass is fixed. State how and under what circumstances this is accomplished and monitored.

c. For any scrubber with a bypass, provide the percentage flow that has bypassed the scrubber, based on a monthly average, for the years 2008 through 2013, inclusive.

[131] Moretti, A., pp. 10-11.

d. State the maximum SO_2 removal efficiency of each EGU's scrubber system, based on full EGU operating capacity, assuming the optimum amount of reagent usage (including dibasic acid or other organic acids), and the type of coal being burned. Either report this value assuming 100% of each coal type burned, or by the sulfur content of the coal being burned. In reporting this value, do not multiply the efficiency of the scrubber by the percentage of flow going to the scrubber – report only the efficiency of the scrubber.

e. State the maximum percentage of flow at maximum EGU operating capacity that can be directed to the scrubber and treated at the scrubber's maximum efficiency. Either report this value assuming 100% of each coal type burned, or by the sulfur content of the coal being burned.

f. Describe what improvements have been made to the efficiency of the scrubber system since its initial installation, including but not limited to reagent handling and milling, addition of dibasic acid or other organic acids, bypass elimination, absorber (e.g., trays, liquid distribution rings, sprayers, recycle pumps, etc), stack lining, etc.

    i. Provide the capital costs for these projects and the dates when each upgrade was installed and became operational.

    ii. Provide the percentage improvement in the scrubber system for each of these upgrades that were separately installed.

Because the San Miguel facility provided similar information in response to emails and telephone requests, we did not send them a request for information under Section 114(a). All of these units complied with our Section 114(a) requests, but most of the information provided was claimed as Confidential Business Information (CBI) under 40 C.F.R. Part 2, Subpart B. We were able to review and analyze that information to assist us in calculating the costs of upgrading the scrubbers for those units. However, because our analyses largely depends on that information and is thus CBI itself, we can only present a summary of it here. Since the San Miguel facility did not assert any CBI information, our assessment of its scrubber is presented here and the information that San Miguel's provided is in our docket in full.

7.2 Approach to Scrubber Upgrade Cost Analyses

Each of the units listed in Table 18 had contracted with engineering firms (sometimes multiple engineering firms) and conducted multiple SO_2 scrubber upgrade cost analyses, which we were able to review as a result of our Section 114(a) requests. Many of these cost analyses were very detailed. Most of these analyses occurred in the 2004 – 2006 timeframe. They were done because the facilities had concluded that considering the price of SO_2 allowances, upgrading their scrubbers would result in an annual cost savings as they could either stop buying SO_2 allowances, or even sell excess SO_2 allowances. In addition, in a number of cases, the companies had concluded that upgrading various pieces of equipment related to their SO_2 absorbers that either required constant maintenance, or due to their poor initial design caused other problems, would additionally result in annual cost savings.

These scrubber upgrades concentrated on optimizing the unit's total SO_2 removal, with the primary goal being the elimination or minimization of the scrubber bypasses. In most cases, these cost analyses included the following:

- Additional induced draft fan capacity and upgrading of the electrical distribution system to handle the additional load.
- Upgrading of the absorber(s) spray header to more efficient designs.
- Using all available slurry recycle pumps.
- Replacement of the mist eliminators with more efficient designs.
- Use of absorber trays or liquid distribution rings.
- Flow studies to identify flow maldistribution across multiple absorbers and the use of turning vanes (flow straightening baffles used in duct work) to correct this situation.
- Conversion to wet stack operation, which in most cases involved the demolition of the existing stack and the construction of a new wet stack.

In addition, some of the units' cost analyses included either upgrading or the addition of new DBA systems and forced oxidation systems.

Many units completed some of this work, which usually involved the upgrading of absorber internals (e.g., spray headers, recycle pumps, trays, liquid distribution rings, etc.). Many also partially reduced their scrubber bypasses because upgrading their absorbers allowed them to cost effectively treat more flue gas. None, however, with the exception of San Miguel, totally eliminated their scrubber bypasses.

Our approach to analyzing the cost of a unit's scrubber upgrade was the same in all cases except for San Miguel and consisted of the following basic steps:

- Conduct a literature search of published information from all available non-proprietary sources on any work conducted at the subject facility.
- Review the responses to our Section 114(a) request.
- Construct a timeline of all SO_2 pollution control equipment installations or upgrades, noting what work had already been done so it could be eliminated from our cost analysis.
- Determine what additional equipment is necessary in order to eliminate the SO_2 scrubber bypass and ensure that the unit's overall SO_2 removal efficiency is at least 95%.
- Use the company's scrubber upgrade analyses to estimate the capital and operating costs of eliminating the SO_2 scrubber bypass and ensure that the unit's overall SO_2 removal efficiency is at least 95%.
- Escalate the capital and operating costs to 2013 dollars.
- Annualize the capital and operating costs and calculate the cost effectiveness ($/ton) using the same methodology used in our DSI and scrubber retrofits in Sections 3, 4, and 5, above.
- Weigh the cost of the scrubber upgrades against the visibility improvement at the affected Class I areas.

We discuss how we analyzed San Miguel for potential scrubber upgrades section 7.3.1 below.

7.3 Summary of Scrubber Upgrade Cost Results

With the exception of San Miguel, we are limited in what information we can include in this section, because in developing our scrubber cost estimates we used information that was claimed as CBI. This information was submitted in response to our Section 114(a) requests. We can therefore only present the following summary.

With the exception of San Miguel, we propose to find that for all the units we analyzed:

- The absorber system had either already been upgraded to perform at an SO_2 removal efficiency of at least 95%, or it could be upgraded to perform at that level using proven equipment and techniques.
- The SO_2 scrubber bypass could be eliminated, and the additional flue gas could be treated by the absorber system with at least a 95% removal efficiency.
- Additional modifications necessary to eliminate the bypass, such as adding fan capacity, upgrading the electrical distribution system, and conversion to a wet stack could be performed using proven equipment and techniques.
- The additional SO_2 emission reductions resulting from the scrubber upgrade are substantial and cost effective.

A summary of our analyses is as follows:

Table 19. Summary of Scrubber Upgrade Results

Unit	2009-2013 3-yr Avg. SO_2 Emissions (eliminate max and min) (tons)	SO_2 Emissions at 95% Control (tons)	SO_2 Emissions Reduction Due to Scrubber Upgrade (tons)	SO_2 Emission Rate at 95% Control (lbs/MMBtu)
W. A. Parish WAP8	2,586	836	1,750	0.04
Monticello 3	13,857	1,571	12,286	0.06
Sandow 4	22,289	4,625	17,664	0.20
Martin Lake 1	24,495	3,706	20,789	0.12
Martin Lake 2	21,580	3,664	17,917	0.12
Martin Lake 3	19,940	3,542	16,389	0.11
Limestone 1	10,913	2,466	8,446	0.08
Limestone 2	11,946	2,615	9,331	0.08
Total SO_2 Removed			**104,572**	

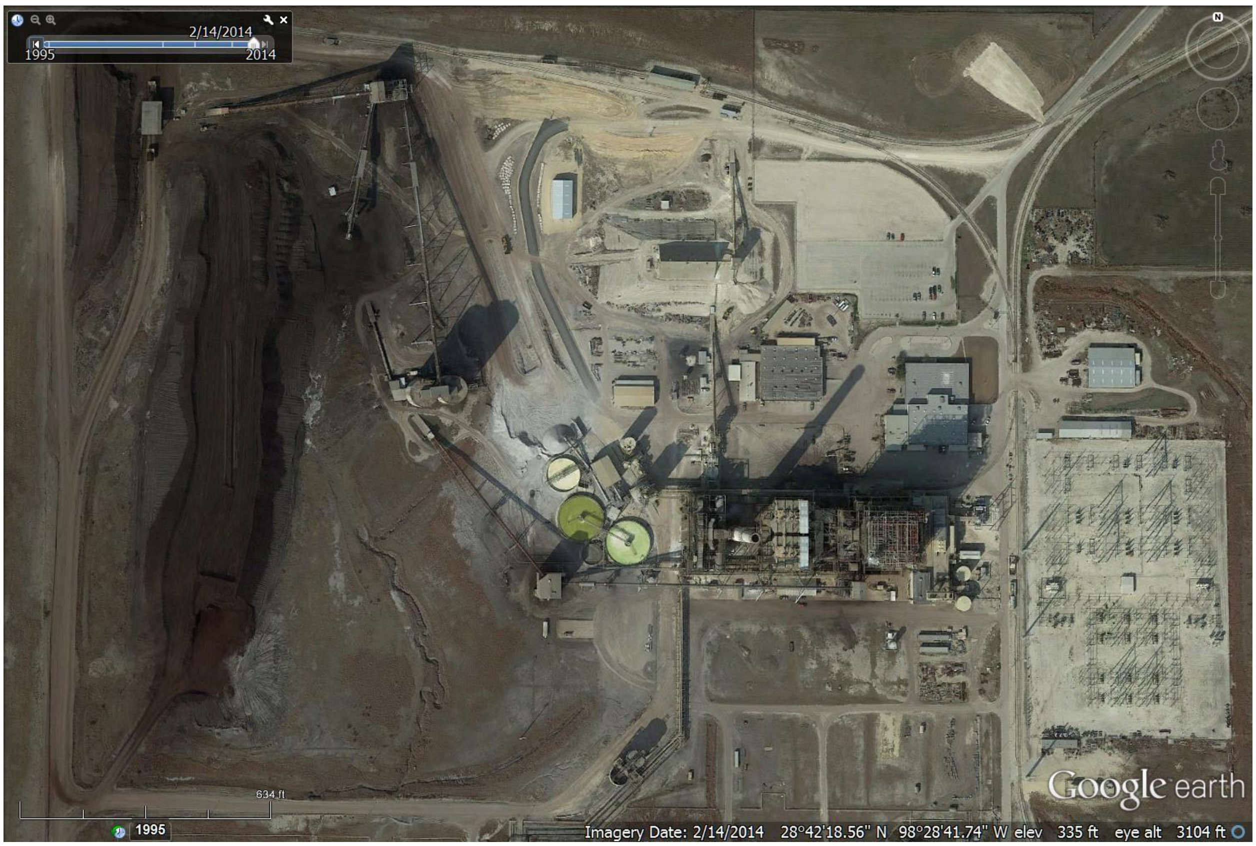
We calculated the cost effectiveness for each of these units. Because those calculations depended on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was less than $600/ton. We invite the facilities listed above to make arrangements with us to view our complete cost analysis for their units.

7.3.1 San Miguel

The San Miguel facility is located near Christine, within Atascosa County, Texas. It consists of one unit, which is a wall fired boiler, rated at 390.3 MW and became operational in 1982. Unit 1 burns a high sulfur lignite.

According to the EIA, it employs OFA and LNBs to control NOx, and a cold side ESP to control PM. A wet limestone FGD manufactured by Babcock and Wilcox was installed with the boiler in 1982 to control SO_2. Each scrubber includes four absorbers, all of which operate at 100% load. It does not employ a bypass. EIA does not indicate that San Miguel utilizes a DBA system to improve SO_2 removal efficiency, but the facility does in fact utilize a DBA system. Weilert and Meyer report that the San Miguel scrubber utilizes inhibited oxidation.[132]

Figure 3. Aerial view of the San Miguel facility



According to information provided by San Miguel,[133] its SO_2 scrubber's original 1982 design efficiency was 86% with an average efficiency of approximately 84%. It was equipped with a

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[132] Weilert, C., and Meyer, E., Utility Design Trends, Power Engineering, 8-1-2010; personal communication. See summary of this data elsewhere in Section 6.

[133] Email from Joe Eutizi to Joe Kordzi on 5-12-14, and report entitled, "San Miguel Cooperative FGD Upgrade Program Update," transmitted by email from Joe Eutizi to Joe Kordzi on 7-1-14.

bypass, two levels of trays, one level of absorber spray nozzles, and a venturi quencher inlet section. San Miguel's scrubber has undergone a number of upgrades since its installation in 1982:

Table 20. Scrubber Improvements Performed at the San Miguel Facility

Timeframe	Scrubber Improvement
1983/84	Installed DBA to improve limestone reactivity.
2000	Increased DBA usage to improve efficiency up to 90%.
2002	Decreased using bypass except for limited maintenance time frames. Scrubber efficiency was increased to 91%.
2006	Opened venturi & installed concurrent spray nozzles. Replaced course spray absorber nozzles with fine spray absorber nozzles. Scrubber efficiency increased to 93%.
2007	Removed scrubber bypass.
2008	Added turning vanes to inlet ductwork for improved gas distribution.
2009	Added water proof liner to interior of brick liner of the stack and upgraded the breeching expansion joint in the stack.
2010	Replaced absorber spray nozzles with duel cone high efficiency nozzles, improving the efficiency to 94%.
2011/2012	Added anti-sneakage baffles, move quencher sprays to second level of absorber sprays, replaced absorber trays to handle larger flow.
2013	Moved anti-sneakage baffle –was too close to trays and prevented tray flooding. Installed borosilicate block in lower 80' of stack to prevent damage to brick liner (water proof liner installed in 2009 failed in this area of the stack in 2012)
2014	Partial change out of upper tray to improve liquid distribution on trays. Modified sludge handling system to handle the larger heavier sludge due to the improved scrubber chemistry.

San Miguel is a mine mouth lignite fired station. They do not have a rail unloading system so the lignite mined is the only solid fuel that is burned. The sulfur content in the coal varies depending on the area that is being mined. San Miguel reports the following average yearly sulfur percent and Btu value for our lignite for the past 5 years:

Table 21. San Miguel Sulfur Content and Btu Coal Value

Year	% Sulfur	Btu/lb
2009	2.68	5,280
2010	2.82	5,303
2011	2.75	5,280
2012	2.49	5,179
2013	2.38	5,209

San Miguel states that these values would equate to uncontrolled SO_2 emission rates that range from a high of 10.64 lbs/MMBtu to a low of 9.14 lbs/MMBtu. We are unaware of any facility in the United States that burns a higher sulfur coal.

San Miguel provided a 2013 report[134] that detailed the scrubber upgrades that San Miguel has performed. In that report, URS outlines two options for improving the scrubber efficiency:

<u>Option 1 – Modification of Existing Absorber Spray Section (quantities are per absorber)</u>

- Remove the 28 existing six-inch spray nozzles
- Install 28 2205 duplex stainless steel flow splitters or "spiders", one at each six-inch flange where the existing six-inch spray nozzles are currently located. The spiders are approximately two feet tall and split the flow from each six-inch connection (24,000 gpm /28 = 857 gpm) so that it feeds three tangential four-inch nozzles at the bottom of the spider.
- Install three new high-efficiency 4-inch silicon carbide DHC nozzles on each spider. Each DHC nozzle has 286 gpm of flow.
- Install a spray impingement plate on the walls where the spray from the DHC nozzles hits the walls to protect the rubber lining from erosion.
- Repair the existing rubber lining after the impingement plates were installed.

<u>Option 2 – Option 1 plus Move Quench Spray to Absorber Section.</u>

- Option 1 work scope
- Remove the external FRP headers feeding the two existing quench spray levels and existing 20-inch FRP piping that fed those headers back to the 20-inch rubber-lined steel pipe flange.
- Remove the existing internal headers, nozzles, and any non-structural internal beams or other items in the existing quench spray area. Repaired rubber lining at new wall penetrations.
- Install new 20-inch abrasion-resistant FRP piping, supports, and expansion joints from the flange referred to above to the absorber section between the existing sprays and the top tray.
- Relocate (raise by one foot) the existing absorber stiffener beams between the existing sprays and the top tray so they do not interfere with the new header/sprays described below.
- Install six new 12-inch penetration spools (2205 duplex) and six new self-supporting internal headers and support brackets (2205 alloy) between the existing absorber spray and the top tray, approximately in the location of the existing internal absorber stiffener beams described above.
- Install 14 new high-efficiency 3-inch DHC nozzles on each of the six new internal headers for a total of 84 DHC nozzles. Each DHC nozzle has 133 gpm of flow for a total of 11,300 gpm for this new absorber spray section.

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[134] San Miguel Electric Cooperative, FGD Upgrade Program Update, URS, June 30, 2014. This report is in our docket.

- Install 2205 duplex SS spray impingement plates on the walls just below the new spray headers/DHC nozzles.
- Repair the damage to the existing rubber lining incurred while relocating the beams and installing the new spray headers and the spray impingement plates.
- Remove the two existing trays. Reused the existing tray supports as much as possible.
- Install two new 2205 duplex high-efficiency trays with 37% net open area (versus 31.7% net open area for the existing trays).
- Conduct CFD modeling to evaluate gas and liquid flow patterns from the modified equipment to determine the extent of the wet-dry interface, alloy wall papering needed, and the design of an internal baffle to smooth the gas flow immediately upstream of the bottom tray.
- Install C-276 alloy wall papering in the new wet/dry interface areas and baffle as needed based on the CFD modeling.
- Remove existing rubber lining as needed to install the wall paper and the baffle.

A key goal of the both Option 1 and 2 was to reduce the reliance on DBA, while improving the SO_2 removal efficiency, in order to reduce the scrubber's annual operating expenses. URS reports that the estimated total project cost (engineering, procurement, and construction) for Option 1 was $1,600,000 and for Option 2 was $8,800,000.

URS states that prior to the start of the upgrade program, the San Miguel FGD system required a DBA level of approximately 1400 ppm to achieve 94.75% SO_2 removal while firing lignite with an average sulfur content of 9.6 lb/MMBtu, resulting in an annual cost of DBA of about $2.7 million dollars.

Option 1 was designed to achieve the same 94.75% SO_2 removal with a higher 10.5 lb/MMBtu coal with a lower DBA concentration of about 725 ppm and an annual cost of DBA of about $1.46 million per year. This represented a savings of about $1.3 million per year, with a nearly 10% greater lignite sulfur content. Option 2 was designed to achieve the same 94.75% SO_2 removal with 10.5 lb/MMBtu lignite with an even lower DBA concentration of about 125 ppm, and an annual cost of DBA of about $250,000. This represented a savings of about $2.5 million per year, with a nearly 10% greater lignite sulfur content.

San Miguel elected to initially install the Option 1 scrubber upgrade in all four of its absorber modules during its spring 2010 outage, and the Option 2 scrubber upgrade during its spring outage in 2012. San Miguel subsequently further upgraded the scrubber system by making improvements to the tank agitators in 2011 - 2012, and again replacing its trays with an improved design during the spring 2014 outage. URS states that it appears the FGD system is currently operating as intended both from a chemical and physical design standpoint. The most recent performance data collected with the unit at full load during May and June, shows that the FGD system is achieving approximately 94% SO_2 removal efficiency at absorber DBA concentrations of about 400 ppm.

Table 22. Summary of SO_2 Emissions from the San Miguel Facility

	2009	2010	2011	2012	2013	2009-2013 Average
Annual monitored emissions (tpy)	11,064.4	10,151.2	10,123.4	10,950.2	8,985.1	10,254.9
Calculated uncontrolled SO_2 emissions (tpy)	179,595.1	181,455.2	185,834.6	165,495.7	140,094.5	170,495.0
Average estimated control level	93.8%	94.4%	94.6%	93.4%	93.6%	94.0%
Annual monitored SO_2 emission rate (lb/MMBtu)	0.64	0.63	0.60	0.63	0.58	0.62
Calculated uncontrolled SO_2 emission rate (lb/MMBtu)	10.30	10.63	10.40	9.59	9.12	10.03

The above table was constructed from the file, "Coal vs CEM data 2009-2013.xlsx," which is in our docket. "Annual monitored emissions (tpy)," represents the average annual SO_2 emissions as reported to our Air Markets Program Data website.[135] "Calculated uncontrolled SO_2 emissions (tpy)" represents what the theoretical calculated annual SO_2 emissions would be if San Miguel had no SO_2 scrubbers, based on coal dated reported to the EIA. The last two rows are similarly explained.

[135] http://ampd.epa.gov/ampd/

San Miguel's monthly SO_2 emission data from 2013 is:

Table 23. 2013 Monthly SO_2 Emission Data for the San Miguel Facility

Year	**Month**	**Operating Time (hours)**	**SO_2 (tons)**	**SO_2 Emission Rate (lbs/MMBtu)**
2013	1	744	886.184	0.544
2013	2	671.5	759.849	0.569
2013	3	49.75	74.948	0.710
2013	4	668.5	753.295	0.587
2013	5	344.75	383.038	0.594
2013	6	720	917.028	0.637
2013	7	731	922.075	0.581
2013	8	649	795.605	0.626
2013	9	379	439.158	0.530
2013	10	728.75	967.086	0.552
2013	11	720	1104.451	0.624
2013	12	744	982.405	0.545
2014	1	536	510.134	0.425
2014	2	511	554.017	0.519
2014	3	1	0.047	0.079
2014	4	127	126.051	0.572
2014	5	743.5	925.666	0.580
2014	6	720	811.227	0.521

We propose to conclude that the San Miguel facility has upgraded its SO_2 scrubber system to perform at the reasonably highest level that can be expected, based on the extremely high sulfur content of the coal being burned, and the technology currently available. We conclude, based on the scrubber upgrades it has recently performed and its demonstrated ability to maintain an emission rate below this value on a monthly basis from December 2013 to June 2014 that it can consistently achieve this emission level.